Seventh International Williston Basin Horizontal Well Workshop

Sponsored by:

North Dakota Geological Survey

Saskatchewan Energy and Mines

April 25-27, 1999

Delta Regina Hotel

Regina, Saskatchewan

Canada

Saskatchewan
Energy and Mines

100-05923/

A MESSAGE FROM

SASKATCHEWAN ENERGY AND MINES

On behalf of Saskatchewan Energy and Mines I would like to welcome you to the Seventh Williston Basin Horizontal Well Workshop and the third held in Regina.

As many of you are aware, the original intent of the Workshop was to promote business opportunities on both sides of the border as well as stimulate technology transfer. The growth of registration levels suggests that we have achieved success in both of these workshop goals. We hope that you take advantage of the workshop to renew acquaintances and to learn more about horizontal wells and opportunities in the Williston Basin.

I trust that you will enjoy the Workshop and your stay in Regina.

Ray Clayton
Deputy Minister
Saskatchewan Energy and Mines

April, 1999

State of North Dakota

OFFICE OF THE GOVERNOR
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EDWARD T. SCHAFER
GOVERNOR

TO THE

PARTICIPANTS, EXHIBITORS, & GUESTS

OF THE

SEVENTH INTERNATIONAL
WILLISTON BASIN
HORIZONTAL WELL WORKSHOP

APRIL 25-27, 1999
REGINA, SASKATCHEWAN

Greetings from the Governor's Office. I am honored to join our Canadian neighbors in welcoming you to this international workshop. My thanks to the North Dakota Geological Survey and Saskatchewan Energy and Mines for hosting what has become a valuable and now timely conference.

From reports by government agencies, presentations of academic studies, and the latest in industry news, this workshop provides the opportunities to discuss a wide range of issues and the immediate and long range impact on the oil and gas industry. I extend a special welcome to the speakers and special guests, knowing your comments and information will be welcomed and appreciated.

The continued growth and strength of the oil and gas industry is vital to the future of our province and state. I wish to take this opportunity to thank each of you for your continued interest in our region, and wish you the best for continued health, happiness, and success.

Sincerely,

Ed Schafer

Edward T. Schafer
Governor

Seventh International Williston Basin Horizontal Well Workshop

List of Sponsors

We sincerely thank our industry sponsors for their generous support to help make this a successful meeting!

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THE PETROLEUM TECHNOLOGY RESEARCH CENTRE (PTRC)

Who is the PTRC?

The PTRC is a new, non-profit corporation located in Regina, Saskatchewan. As a research and development organization, the PTRC brings a fresh approach to finding, developing and applying innovative technology and engineering solutions for the petroleum sector.

The PTRC was created as a collaborative initiative of Natural Resources Canada (NRCan), Saskatchewan Energy and Mines (SEM), the University of Regina and the Saskatchewan Research Council (SRC). The PTRC has financial support from the federal and provincial governments to sponsor research and development projects initially for five years. It is expected that the PTRC will attract support for its projects from the petroleum industry to complement the support it receives from government.

The Engineering Faculty of the University of Regina and the Petroleum Division of the SRC will undertake the research and development projects funded through the PTRC. It is expected that most of the projects will be conducted jointly by these two research entities. They will also have the ability to collaborate with other research organizations in Canada and elsewhere, as needed, to achieve specific project objectives.

What will the PTRC do?

The PTRC will initiate and support research and development projects aimed at enhancing the production and recovery of Canadian petroleum resources. Building and drawing on the expertise of the Petroleum Division of the SRC and the Engineering Faculty of the University of Regina, the PTRC will promote projects in the following areas of research:

- New enhanced oil recovery techniques that are economic, environmentally appealing and applicable to marginal reservoirs;
- Better techniques to describe and understand reservoir phenomena;
- Solutions to production problems such as well bore plugging, corrosion, emulsion treatment and other production problems;
- Techniques to minimize the environmental impact and maximize energy efficiency of petroleum production; and
- More accurate mathematical and physical models of petroleum and environmental processes.

In addition to supporting research and development projects, the PTRC will ensure that the findings of the work it supports are made available for possible application by the petroleum industry.

Why should the PTRC be considered for petroleum research and development services?

The PTRC is a unique petroleum research and development organization in Canada. It brings government, industry and academia together to pursue the common goal of developing relevant technologies. With the complimentary strengths and expertise of these partners, the PTRC is capable of taking an idea from bench scale basic research and development to field scale demonstration. PTRC will pursue research and development activities that are of strategic importance to industry. The PTRC Board of Directors has six senior leaders from the petroleum industry.

The University of Regina has established Canada's largest academic petroleum engineering program. Faculty members, graduate and undergraduate students will be conducting innovative research based on fundamental observations of chemistry and physics. An interdisciplinary approach will be taken to complete many projects that will involve a team of scientists from petroleum engineering, chemical engineering, computer engineering, computer scientists, environmental engineers and geophysics. Priority will also be given to research projects that address environmental concerns or challenges.

The Petroleum Division of the SRC brings 15 years of experience in applied research and development of innovative technologies to improve the recovery and production of the petroleum resources of Saskatchewan. In addition to client confidence and recognition, the Petroleum Division has experienced engineers and scientists on staff, and has a large laboratory and research infrastructure. The Petroleum Division has an established research program in horizontal well technology, emulsions research, CO_2 injection in light and medium oil reservoirs, heavy oil recovery by methane pressure cycling, improved recovery by air injection and development of field-scale technologies. The Petroleum Division also has access to the SRC Petroleum Analytical Services laboratory and the SRC Pipeline Technology Centre.

The Petroleum Division and the Petroleum Engineering Group bring combined resources of 50 researchers and staff. This number is expected to double over the next several years.

Where is the PTRC?

The PTRC will be located in a new 55,000 square foot, dedicated facility at the University of Regina. The new building will be constructed to provide state-of-the-art laboratories and equipment for researchers of the Petroleum Engineering Group (University of Regina) and the Petroleum Division (SRC). The PTRC building will be the first research facility to be built to an energy efficiency C2000 standard in Canada.

When will the PTRC be operational?

The PTRC was legally incorporated in November 1998. It will receive its first year of funding from SEM and NRCan before the end of March 1999. The first project has been approved and will be completed by the end of March 1999. The new specialized building for the PTRC will be constructed, fully equipped and open by the second quarter of 2000.

7TH INTERNATIONAL WILLISTON BASIN HORIZONTAL WELL WORKSHOP

April 25-27, 1999 - Delta Regina Hotel
Regina, Saskatchewan, CANADA

AGENDA

SUNDAY APRIL 25, 1999

4:00 p.m. Poster / Display set-up

5:30-8:00 p.m. Registration

6:00-11:00 p.m. Reception / Ice Breaker (Poster Exhibits open)

MONDAY APRIL 26, 1999

7:00 a.m. Breakfast for Monday Speakers and Chairs

7:30-11:00 a.m. Registration

8:15-8:30 Welcome from City of Regina
Mayor Doug Archer

8:30-8:45 Opening Remarks

Monday A.M. Chairs: John Bluemle, State Geologist - North Dakota Geological Survey
George Patterson, Executive Director Exploration and Geological Services - Saskatchewan Energy and Mines

8:45-9:35 State / Provincial Horizontal Well Activity Updates
Montana: Larry Smith - Montana Bureau of Mines and Geology
- Montana Horizontal Well Update
South Dakota: Gerald (Mack) McGillivray - South Dakota Dept. of Env. & Nat. Res.
- South Dakota Horizontal Drilling Update
Manitoba: John Fox - Manitoba Energy and Mines
- Horizontal Drilling Activity in Manitoba
North Dakota: Bruce E. Hicks - NDIC Oil & Gas Division
- North Dakota Horizontal Update
Saskatchewan: Chris Wimmer - Saskatchewan Energy and Mines
- Saskatchewan Williston Basin Horizontal Well Update

9:35-10:00 Lynn Helms & Bruce E. Hicks - NDIC Oil & Gas Division
Title: *Back from the Brink*

10:00-10:30 Coffee / Poster Exhibits

10:30-10:55 Rafiq Islam - University of Regina
Title: *A Simple Correlation for Estimating Pressure Drop in a Horizontal Well*

10:55-11:20 Brian Stambaugh - NMR Petrophysics
Title: *Nuclear Magnetic Resonance Logging - Considerations for Horizontal Wells*

11:20-11:45 Bob Williams - Mercury Electric
Title: *Mini Turbine Power Generation from Flare Gas*

11:45-1:15 Lunch / Poster Exhibits
Luncheon Address: Honourable Eldon Lautermilch
Minister, Saskatchewan Energy and Mines

Monday P.M. Chairs: Ray P. Hattenbach, General Sales Manager - Dakota Gasification Company
Robert MacCuish, President - Mohall Oil Ltd.

1:15-1:50 Keynote Address
Dr. David Barnard
Board Member, Petroleum Technology Research Centre
Topic: Petroleum Technology Research Centre

1:50-2:15 Roy Cullimore - University of Regina
Title: *Determination of the Potential for Microbiological Plugging in Saskatchewan Oil Wells, a Case Study*

2:15-2:40 Bert von Hertzberg - Fracmaster
Title: *Horizontal Underbalanced Drilling with Coiled Tubing - Advances with Technology*

2:40-3:20 Coffee / Poster Exhibits

3:20-3:45 Darren Wiltse - Weatherford Artificial Lift Systems
Title: *The Use of Continuous Sucker Rod in the Shell House Mountain Field: A Case Study*

3:45-4:10 Andy Limanowka - Centrilift, a Baker Hughes Canada Company
Title: *Electric Submersible Pumping Systems for Applications in Sour Environment*

4:10-4:35 Rafiq Islam - University of Regina
Title: *A New Technique for Cleaning Horizontal Wellbores*

4:35-5:00 Alex Turta - Petroleum Recovery Institute
Title: *Feasibility of Air Injection-based Processes for Williston Basin Reservoirs*

TUESDAY APRIL 27, 1999

7:00 a.m. Breakfast for Tuesday Speakers and Chairs

7:30-10:00 a.m. Registration

8:25-8:30 Welcome - Opening Remarks

Tuesday A.M. Chairs: Mike Monea, President Nautilus Exploration & Associates Inc.
Tom Heck, Geologist - North Dakota Geological Survey

8:30-8:55 Don Kent - D.M. Consulting Geologist
Title: *Diagenesis - the maker and breaker of reservoir rocks in the Frobisher Beds of southeastern Saskatchewan: implications to horizontal wells*

8:55-9:20 Bob Munday - R.W. Shirkey & Associates.
Title: *Ranking Horizontal Wells*

9:20-9:45 Mike Ware - Talisman Energy Inc.
Title: *Exploration Drilling on the Hume Structure: A Possible Astrobleme?*

9:45-10:10 Wayne Friesatz - Sunburst Consulting
Title: *Geosteering*

10:10-10:45 Coffee / Poster Exhibits

10:45-11:10 Stephen Bend, University of Regina & Kim Kreis, Saskatchewan Energy and Mines
Title: *Source Rock Winnipeg Deadwood*

11:10-11:35 Don Kissling - Jackalope Geological Ltd.
Title: *Reservoirs in Winnipegosis Basin Laminites (Ratner Member), Williston Basin*

11:35-12:00 Bill Slimmon - Saskatchewan Energy and Mines
Title: *GIS Demonstration of Oil and Gas Information on the Geological Map of Saskatchewan CD-Rom.*

12:00-1:10 Lunch / Poster Exhibits

Tuesday P.M. Chairs: Ken Brown - PanCanadian
Paul Diehl, Petroleum Geologist - North Dakota Geological Survey

1:10-1:45 Teresa Utsunomiya - PanCanadian
Title: *Mechanical Isolation of Highly Conductive Water Bearing Intervals in Horizontal Wells Weyburn Unit, Saskatchewan*

1:45-2:10 J. B. Surjaatmadja - Haliburton Energy Services Inc.
Title: *SurgiFrac: A Method for Selective Placement of Many Fractures in Uncased Horizontal Wells*

2:10-2:35 Susan Hancock - PanCanadian
Title: *Weyburn CO_2 Project*

2:35-3:00 Len Checknita - Centrilift, a Division of Baker Hughes
Title: *Downhole Oil/Water Separation using ESP's*

3:00 Closing Remarks

MONTANA HORIZONTAL DRILLING UPDATE

Larry N. Smith
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Horizontal drilling for oil in Montana has increased dramatically since 1992 due to continued successful drilling along the Cedar Creek Anticline and reductions in oil and gas production taxes enacted by the Montana State Legislature in 1995 (Figure 1). Horizontal drilling began in Montana in 1988 with Meridian Oil's use of the technology in a Red River Formation pilot waterflood project in East Lookout Butte field on the Cedar Creek Anticline.

A national upswing in activity in 1997 was reflected in a sustained level of drilling and permitting through 1998 in Montana. Of the 70 wells spudded or completed since 1997, nearly all were in the Red River Formation (called Silurian-Ordovician by Shell), except for seven (10%) in the Nisku interval (Figure 2). The majority of wells classed as "unknown" in Figure 2 are believed to be completed in the Red River Formation. As of February 1999, 276 horizontal wells have been completed or have been spudded, of which 202 were originally completed as producers; an additional 16 permits are active (Figure 3). The current status of wells (Figure 4) reflects a decrease in the number of producers due to conversion of producers to injectors and to the temporary or permanent abandonment of wells deemed uneconomic (Figure 4). Activity in the past year has been dominated by Burlington Resources' development of Red River Formation reservoirs in and near established fields along the Cedar Creek Anticline. A major exception is the production of Nisku reservoirs in and outside the Williston Basin by Wascana, Samedan, and Hallwood (Figures 2 and 5).

Cumulative production from all horizontal wells has totaled nearly nine million barrels of oil (MMBO), with only partial reports thus far for 1998 production (Figure 6). Very few wells have produced more than 0.15 MMBO; however, the production history of most wells covers less than 3 years (Figure 7). Two of the better producers completed since 1997 have been Wascana's Nisku wells in the Flat Lake Field. Although only about 19% of Montana's Williston Basin oil in 1997 was produced from horizontal wells, production from these wells has flattened the historic decline in production from this province (Figure 7), which accounts for 79% of production in Montana. The Red River, Silurian-Ordovician, Madison, and Mission Canyon units account for 84% of production to date from horizontal wells (Figure 8).

RED RIVER FORMATION AND SILURIAN/ORDOVICIAN RESERVOIRS

The most extensive history for horizontal wells is that of Burlington Resources' development of Red River Formation reservoirs in the East Lookout Butte Area on the Cedar Creek Anticline. Burlington Resources has spudded or completed 32 wells since 1997 and has another 13 active permits in the area. Horizontal wells completed to date are being used as injectors (17) and producers (45) in a waterflood of the area; another 7 injection wells are permitted. Most of the

horizontal legs are oriented perpendicular to the strike of the fold limb, parallel to the maximum horizontal compressive stress direction. The tax rates, as amended for enhanced recovery projects and horizontal completions, have benefitted the economics of this venture.

Production in Burlington Resources's East Lookout Butte area is on a downdip leg of fields operated by Shell. Shell became inactive in permitting and drilling in Montana during 1997; they recently sold all their Montana holdings to Encore Acquistions Partners of Fort Worth, Texas. Extension of success from North Dakota into Montana by Continental Resources has occurred in the Cedar Creek Anticline area. Continental completed 4 wells since 1997 and has one active permit.

MADISON GROUP

The Madison Group has historically been the second most frequent target for horizontal drilling, after for the Red River/Silurian-Ordovician interval. However, only one well was completed since 1997 in the Madison; there are no active permits (Figure 2). The Ratcliffe interval of the Madison Group was the target of a second completion. All recent completions in the Madison Group have had disappointing results.

OTHER RESERVOIRS

Horizontal drilling in the Nisku/Duperow interval has increased in activity since the first well was completed in June of 1997. Eight wells were completed in the Nisku/Duperow interval since 1997 by Wascana, Samedan, Hallwood, and Burlington Resources, making the interval a significant target in the state (Figure 2). Four of the wells each produced between 10,000 and 60,000 barrels of oil in their first year (Figure 6). Other horizons were targeted in one or two additional wells (Figure 2).

MONTANA TAX CHANGE HIGHLIGHTS

A number of bills were introduced in the 1998-1999 biennial legislature that would affect the oil and gas industry in Montana. The major bills of interest are listed in Figure 9. Production taxes on oil and natural gas were reduced in 1995 and are targeted for further simplification and reduction in Senate Bill 530. At the time of this writing only Senate Bill 200 has been signed into law. Up-to-date information on these and other bills can be searched on the state legislature website at: http://laws.leg.state.mt.us/law/plsql/law0203w$.startup.

ACKNOWLEDGMENTS

Jim Halvorson of Montana's Oil and Gas Conservation Division (406-656-0040) contributed greatly to this paper. The Montana Bureau of Mines and Geology supported this paper and presentation.

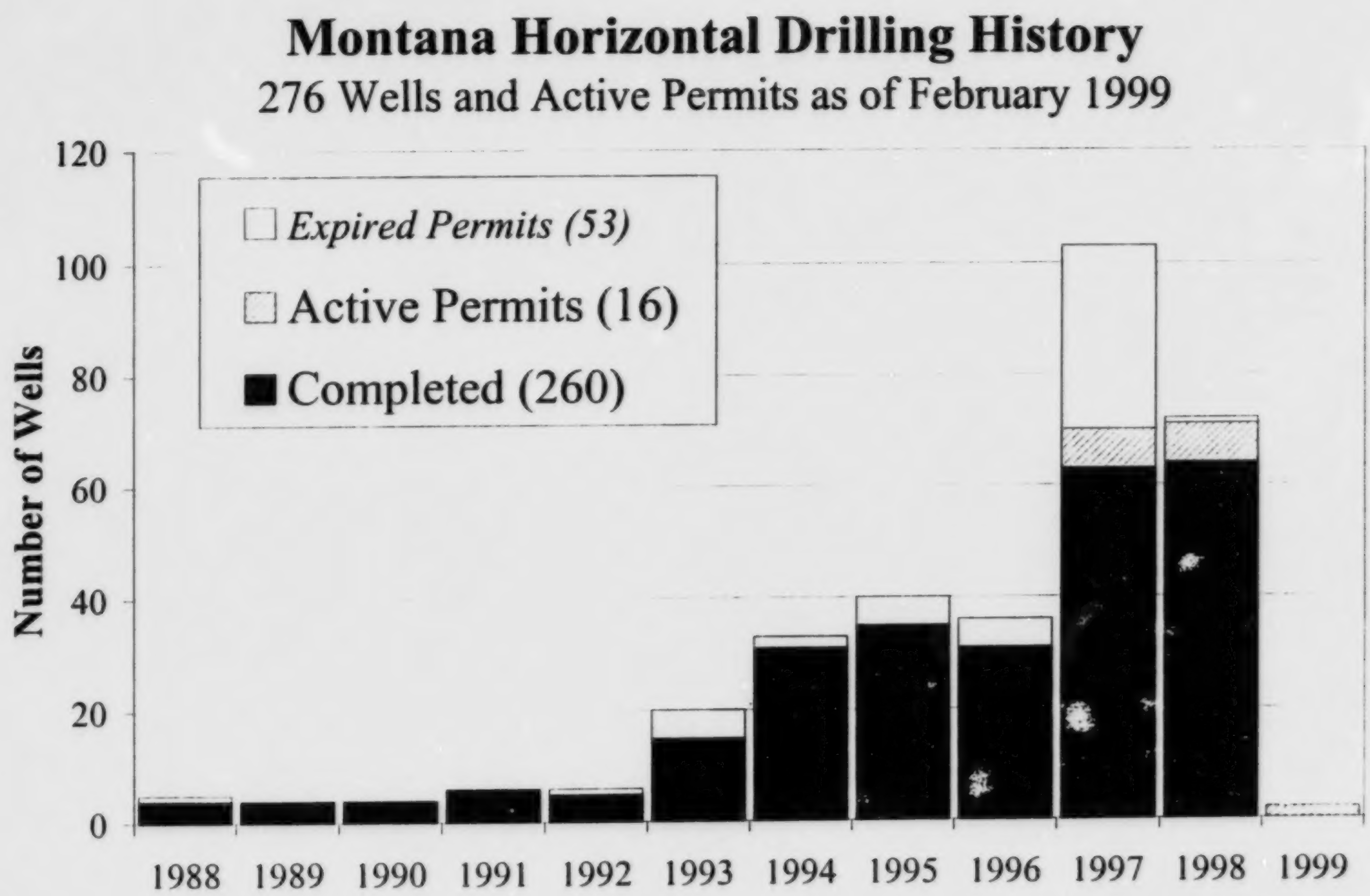

Figure 1 - Drilling history and active and expired permits.

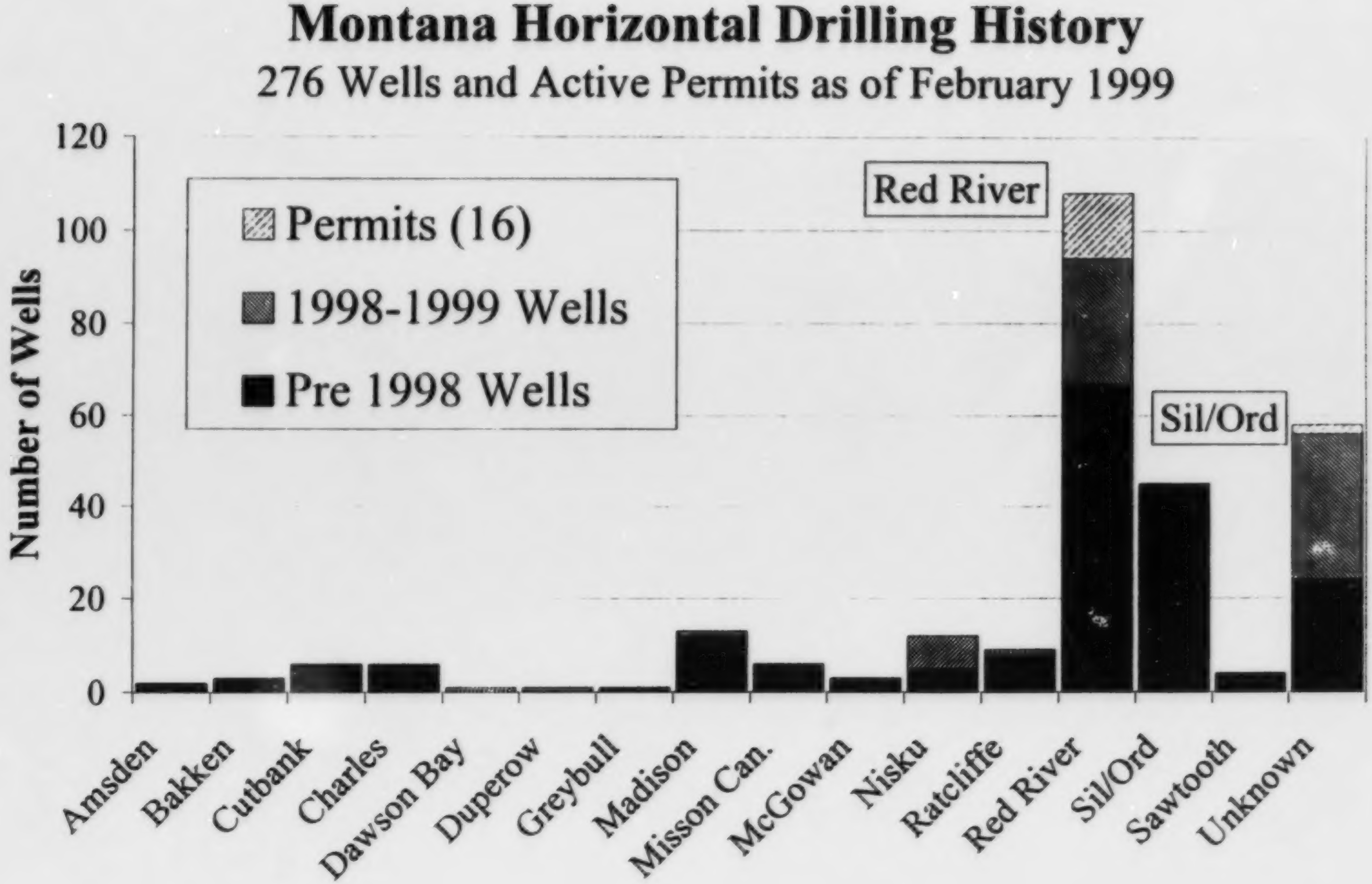

Figure 2 - Drilling and permitting by reservoir.

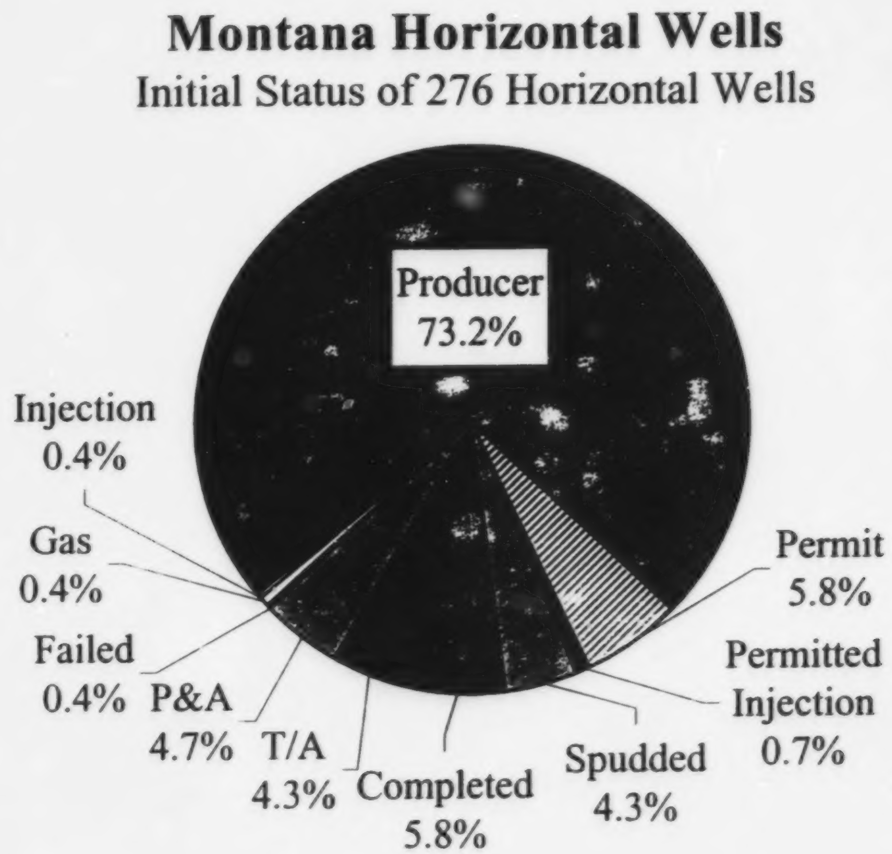

Figure 3 - Initial status of wells when permitted or drilled.

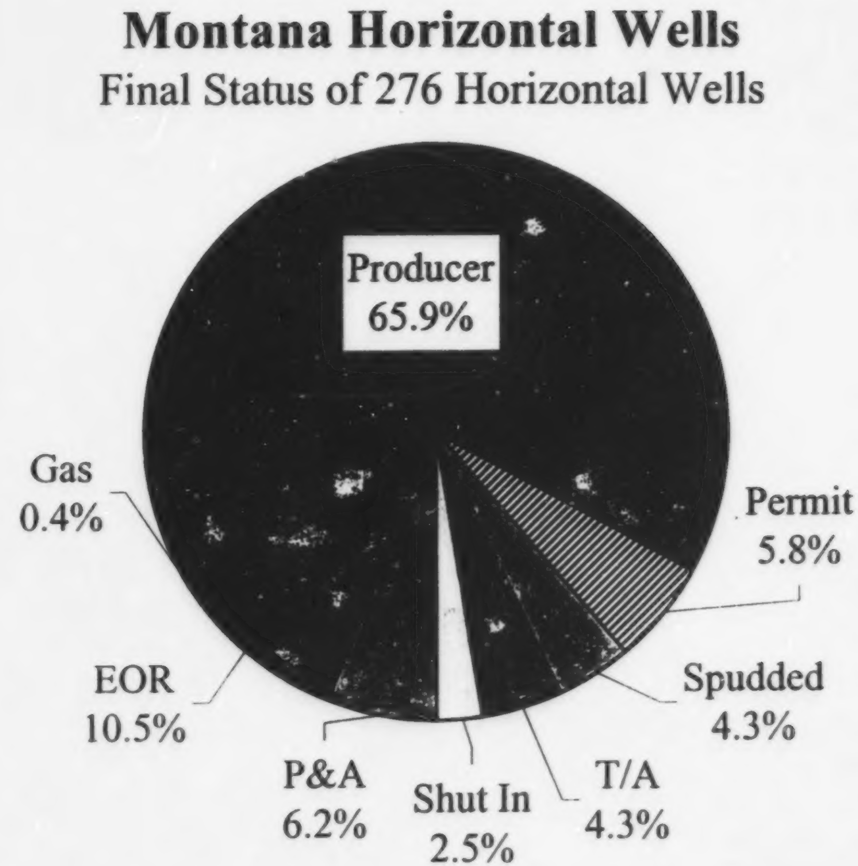

Figure 4 - Current status of wells.

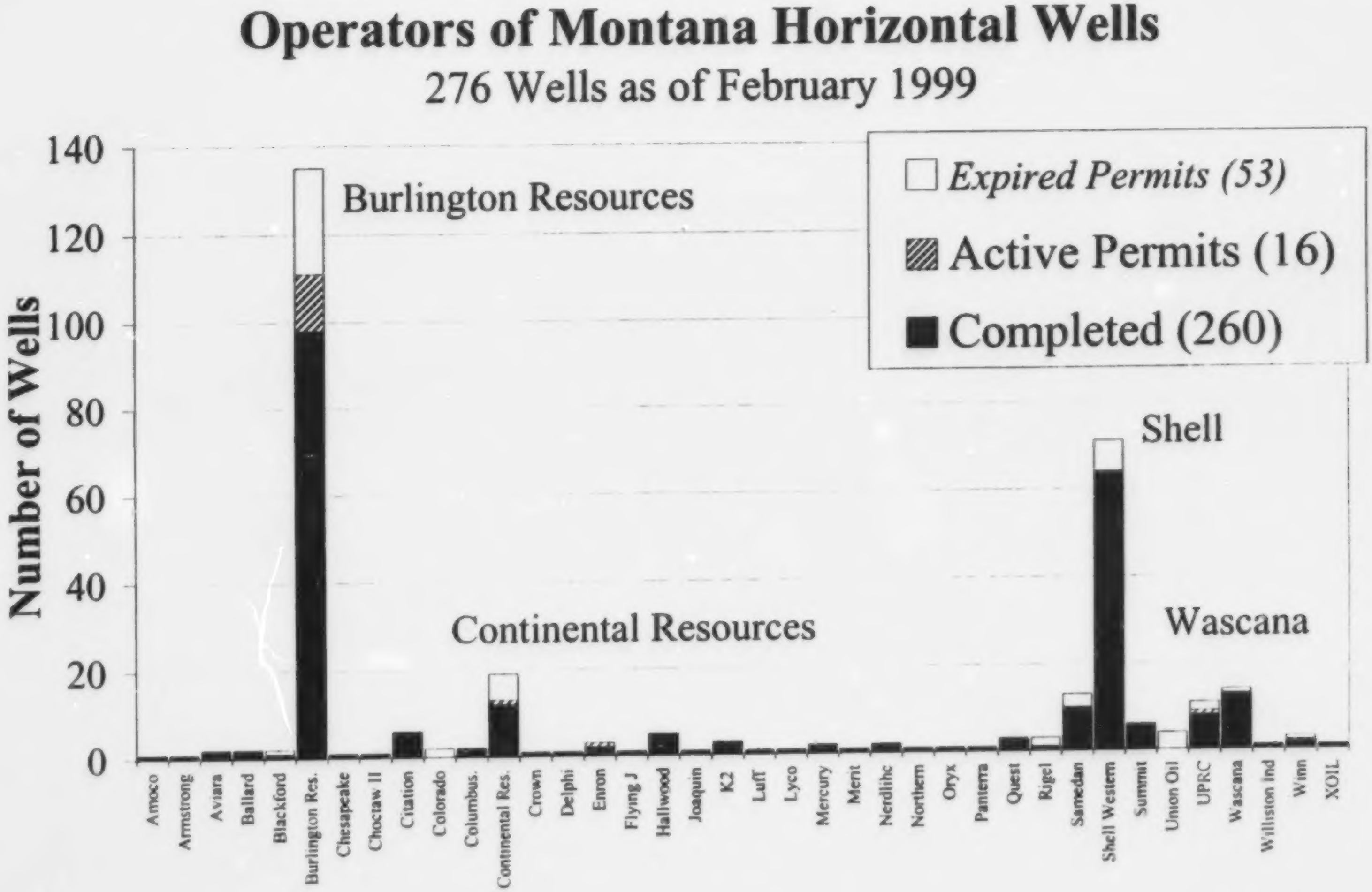

Figure 5 - Drilling and permitting by operator

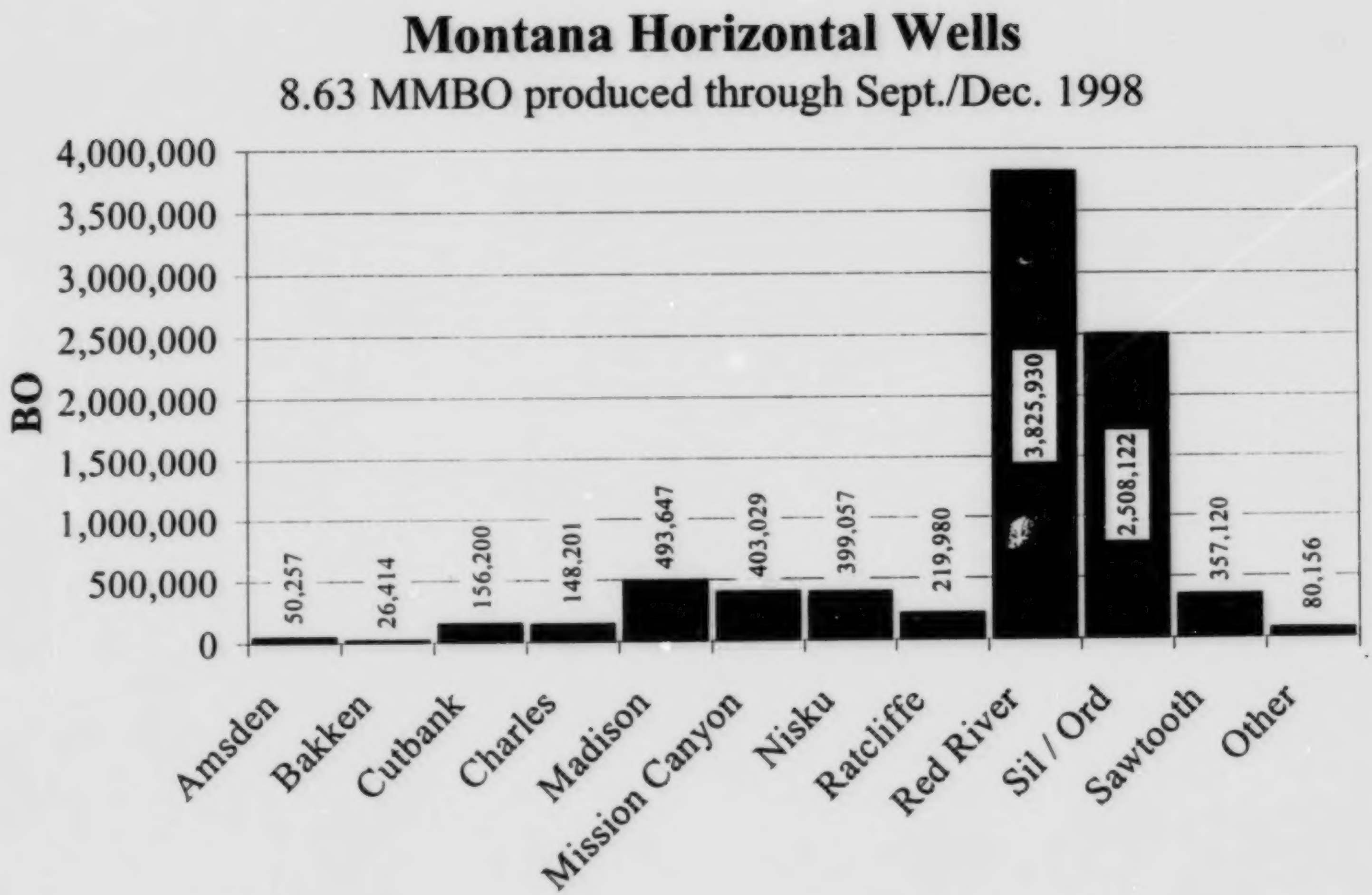

Figure 6 - Production by reservoir.

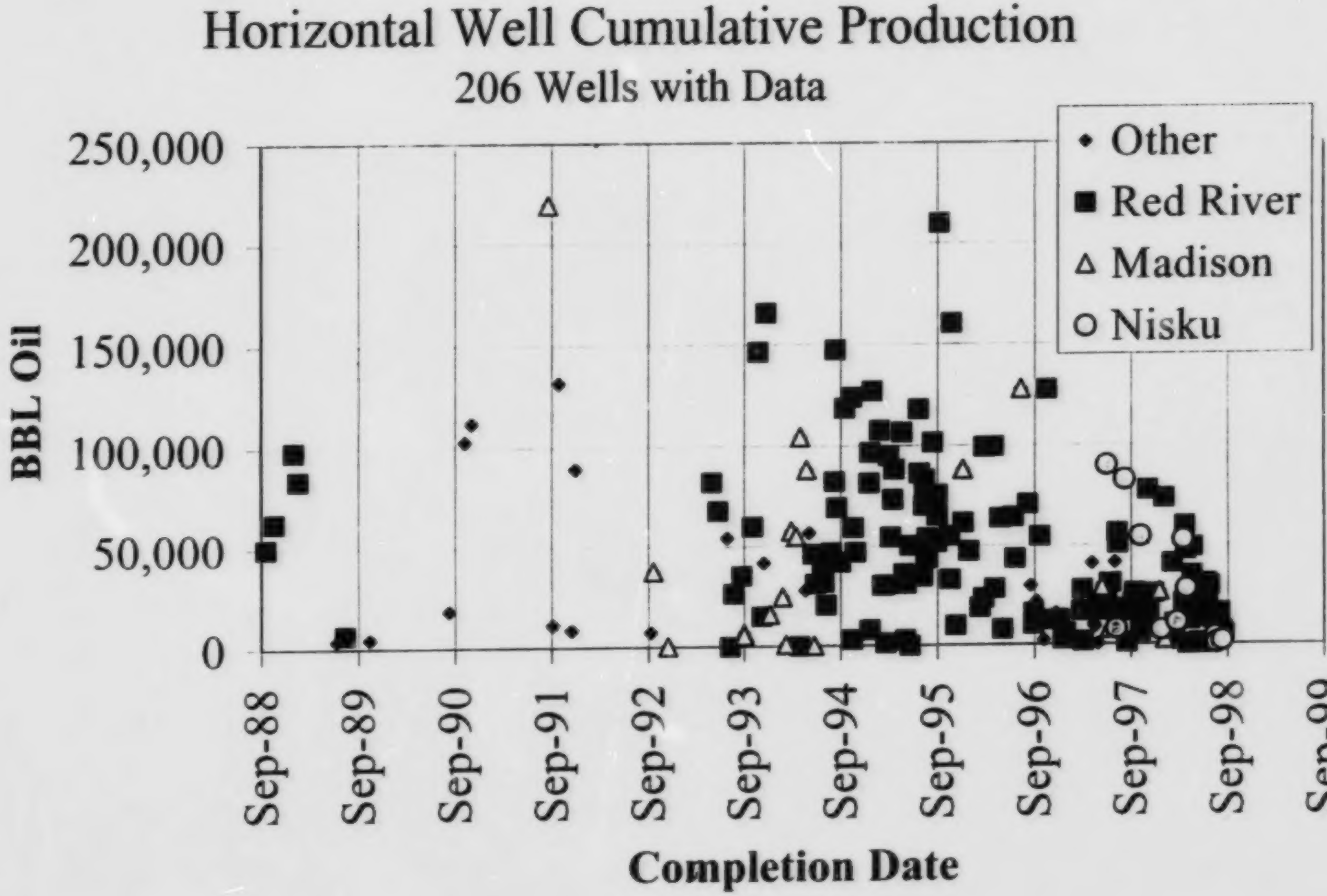

Figure 7 - Cumulative production vs completion date.

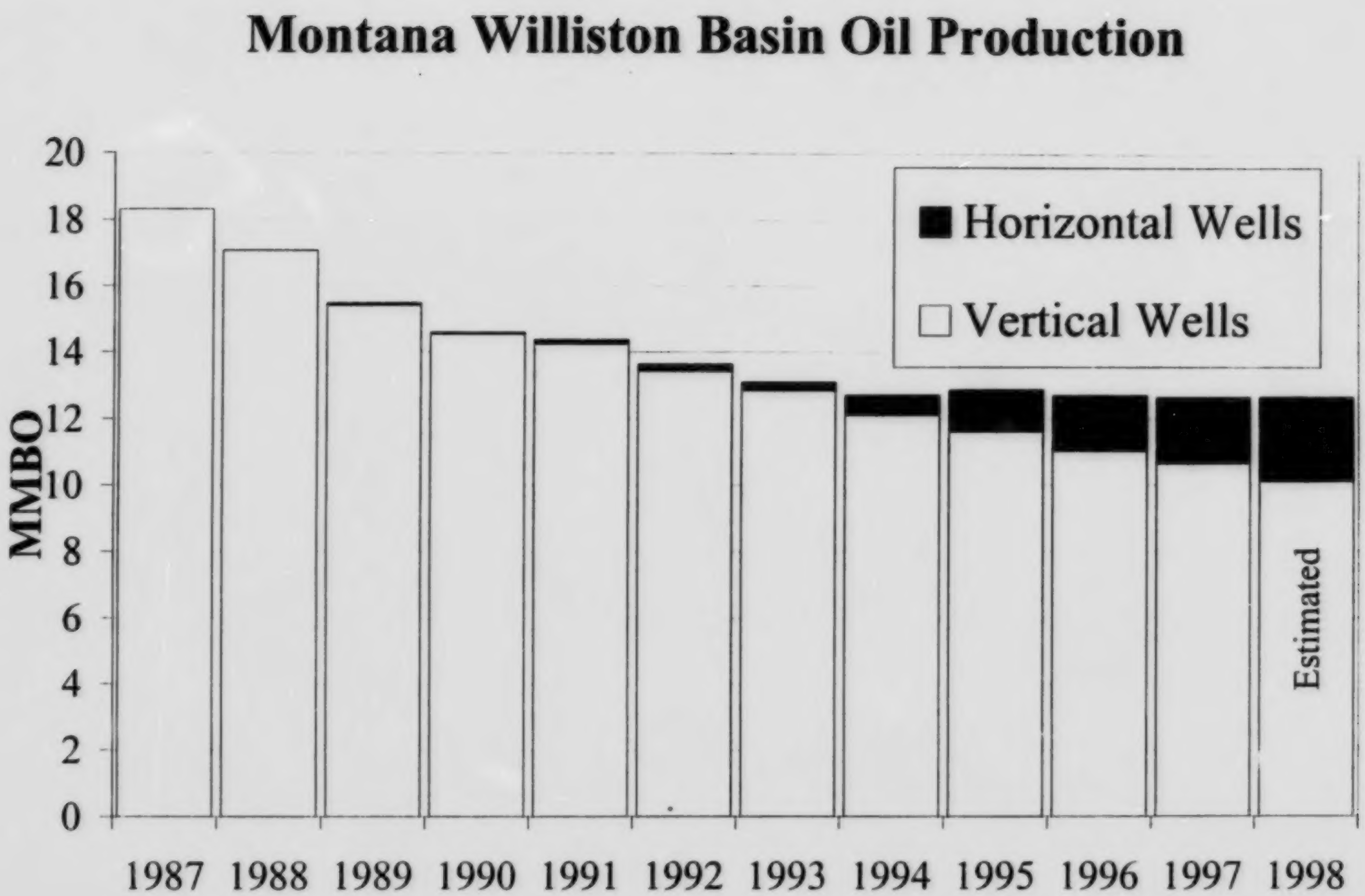

Figure 8 - Oil production in the Montana portion of the Williston Basin.

Tax Change Highlights

http://www.state.mt.us/leg/branch/branch.htm

- SB 200 (signed into law)
  - Reduce or Eliminate Property Tax on Class 6 and Class 8 Property
- SB 249
  - Cap Resource Indemnity Trust Tax Fund
- SB 430
  - Exempt Fee for Royalty Payment Admin. from Production Tax
- SB 530
  - Oil & Gas Production Tax Simplification and Competitiveness
- HB 661 and HB 658
  - Tax Reductions on Stripper Wells

Figure 9 – Legislation affecting oil and gas industry in Montana pending in the 1998-1999 biennium.

SOUTH DAKOTA HORIZONTAL DRILLING UPDATE

Gerald (Mack) McGillivray
South Dakota Department of Environment and Natural Resources
Oil & Gas Program

Following the trend of the rest of the Williston Basin, 1998 was not a good year for horizontal drilling in South Dakota. There was only one well horizontally drilled last year, and it was a re-entry of an existing vertical well.

But, In many respects, horizontal drilling is still relatively new to South Dakota, with most of the horizontal drilling activity having occurred since 1994. The exception is one well drilled in 1988. From 1994 to 1996 horizontal drilling was on the rise, with two wells drilled in 94, three in 95, and seven in 96. In 1997 however, drilling activity fell to five wells, and the one horizontal re-entry drilled and completed in 1998 (Figure 1).

Since 1988, 16 new horizontal wells have been drilled, and 3 existing vertical wells have been re-entered and horizontally drilled. Of those 19 wells, 9 are currently producing; 5 are currently injecting (4 injecting water as part of a water flood project, 1 is injecting air as part of a "fire flood" project); 1 has been temporarily abandoned; and 4 have been plugged and abandoned (Figure 2).

All of the horizontal wells have been drilled in Harding County, and have targeted the Ordovician Red River Formation, primarily the "B" Porosity Zone (Figure 3). The lengths of the lateral sections range from 504 feet to 5109 feet (Figure 4).

To date, the operators conducting horizontal drilling projects and the number of wells they drilled are; Continental Resources (8), Citation Oil & Gas (4), Merit Energy (2), Luff Exploration (2), Burlington Resources (1), Summit Resources (1), and Samedan (1) (Figure 5). Other operators that have established horizontal spacing but have not commenced drilling horizontal wells are Wyoming Resources, Sage Energy, and Kep Energy.

Prior to 1997, oil production from horizontal wells had not contributed significantly to South Dakota's overall crude oil production. Beginning in 1994, one horizontal well produced 4211 barrels, only .2% of the total crude oil output for the state, 1,453,139 barrels. In 1995, two horizontal wells produced 27,422 barrels, about 2% of the state total of 1,352,436 barrels. In 1996, six horizontal wells produced 44,164 barrels, about 3.5% of the state total of 1,257,476 barrels. In 1997 however, eleven horizontal wells (two wells were converted to injection midway in the year) contributed 126,925 barrels, about 9.5% of the state total of 1,334,041 barrels. The good news for 1998 was that although horizontal drilling activity was off, production from horizontal wells contributed more to the states total than in any previous year. In 1998, nine horizontal wells contributed 203,323 barrels, about 17% of the state total of 1,206,463 barrels (Figure 6).

A closer look at 1998 production figures shows monthly oil production from horizontal wells remained fairly consistent through most of the year, while production from vertical wells decreased. The decrease in both vertical and horizontal production is due primarily to wells being idled or shut-in due to low oil prices. During the course of the year, 46 vertical wells were idled or shut-in. By comparison all 9 horizontal wells produced until November, when 2 wells were shut-in. In January the horizontal wells produced 21,066 barrels, about 19% of the state total of 112,994 barrels. In December the horizontal wells produced 13,430 barrels, about 14% of the state total of 93,633 barrels (Figure 7).

Although horizontal drilling activity in South Dakota decreased drastically in 1998 from 1997 levels, there are some signs drilling activity may increase in the near future. One indication of this is the increase in leasing and spacing activity in Harding County. Currently, over 90,000 acres has been spaced for horizontal drilling in Harding County (Figure 8). Most of the horizontal spacing units have been set at 640 acres, or a typical governmental section, with up to 2 wells allowed per section.

Another incentive for increasing horizontal drilling in South Dakota may be the recent update of the Procedures of the Board of Minerals and Environment (Article 74:09) and the Oil and Gas Conservation Rules (Article 74:10), which supplement the oil and gas conservation statute, cited as SDCL Chapter 45-9. The new rules became effective September 8, 1996. For example, prior to that date, an operator desiring to conduct a directional drilling operation had to file a petition with the secretary of the DENR for a contested case hearing before the South Dakota Board of Minerals and Environment (BME), a citizen advisory board appointed by the Governor. After notice and hearing, the BME could issue a permit for the directional drilling operation. Since the requirements for contested case hearings can be a time consuming and expensive process, and the rules did not address the complex issues associated with horizontal drilling, the DENR decided to address these issues with an update of the rules. Along with requiring some additional information to the application to drill a horizontal well, the major change in the rules that affects horizontal drilling is the addition of a new chapter 74:10:11:01, called the "Notice of Recommendation Procedure" or NOR. The NOR allows the DENR Oil & Gas Program staff to deal administratively with applications to drill horizontal wells if they are uncontested (Figure 9). Other applications that can now be handled by the NOR are exception locations, abandoning oil and gas fields, directional holes, multiple zone completions, commingling of oil from separate pools, and underground injection control (UIC) applications or modifications.

Although South Dakota has not yet enjoyed the amount and success of horizontal activity that our neighbors to the North have, there is great potential for increased drilling, horizontal and vertical, in the state. The Williston Basin encompasses portions of 16 counties in the state, over 28,000 sq. mi., and close to 18 million acres (Figure 10). Currently, only two of those counties, Harding and Dewey, have oil and gas production. And this production only affects about 30,000 acres. This leaves a vast, essentially unexplored, area that has the potential to greatly increase the oil and gas reserves of South Dakota.

FOR MORE INFORMATION CONTACT:

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OR MACK MCGILLIVRAY (GEOLOGIST) email: mackm@denrrapcty.state.sd.us
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2050 WEST MAIN, SUITE #1
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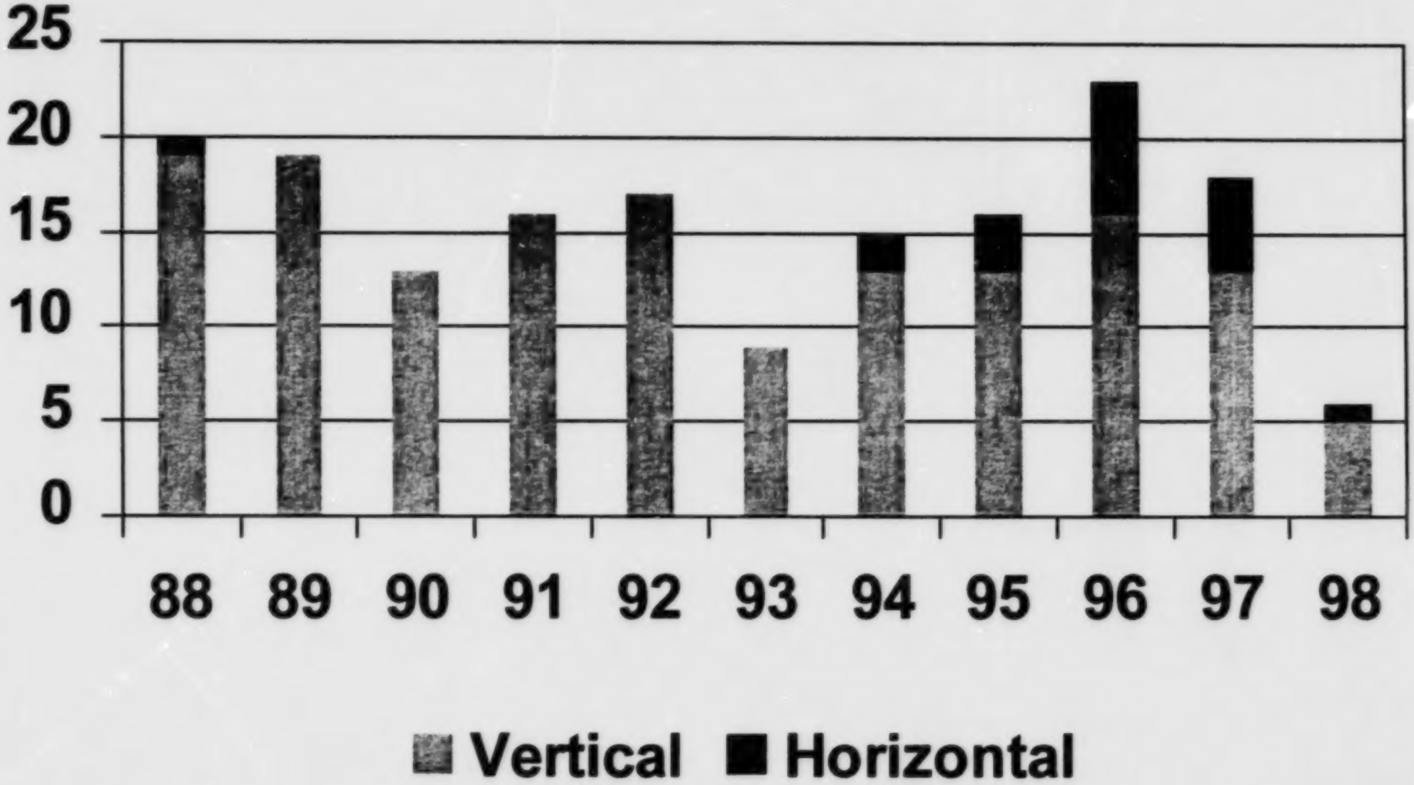
South Dakota Horizontal/Vertical Drilling
1988 - 1998



SD DENR - Oil & Gas Program 3/22/99 Figure 1

South Dakota Horizontal Wells
19 Wells as of March 1999

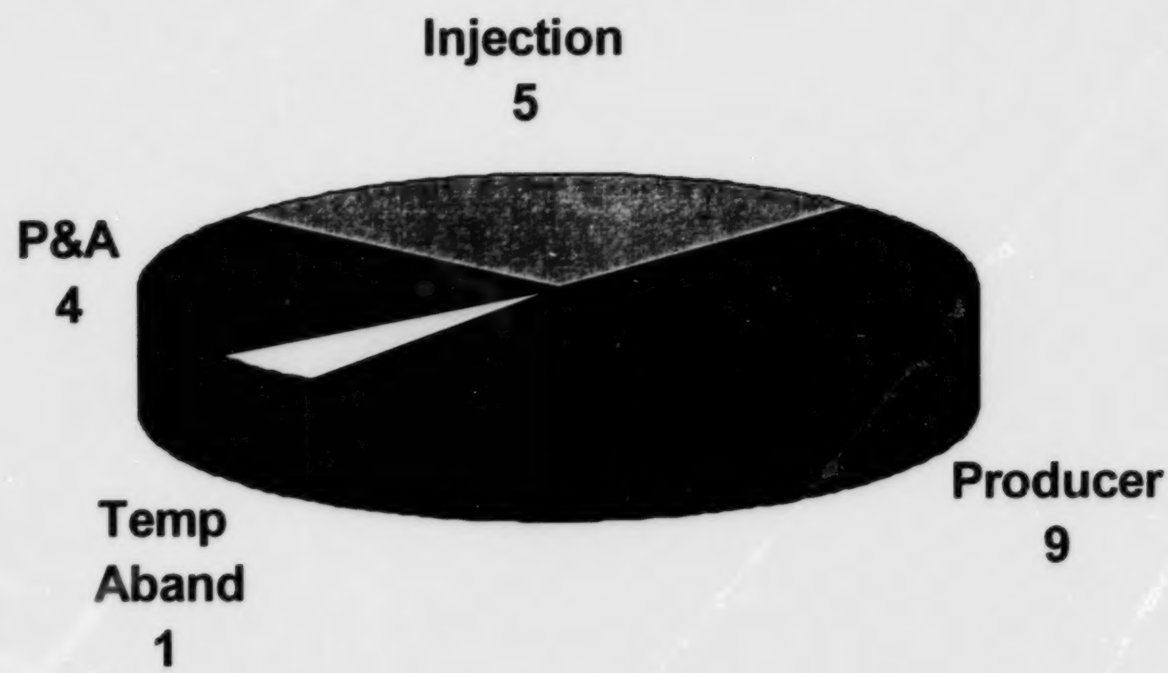


Figure 2

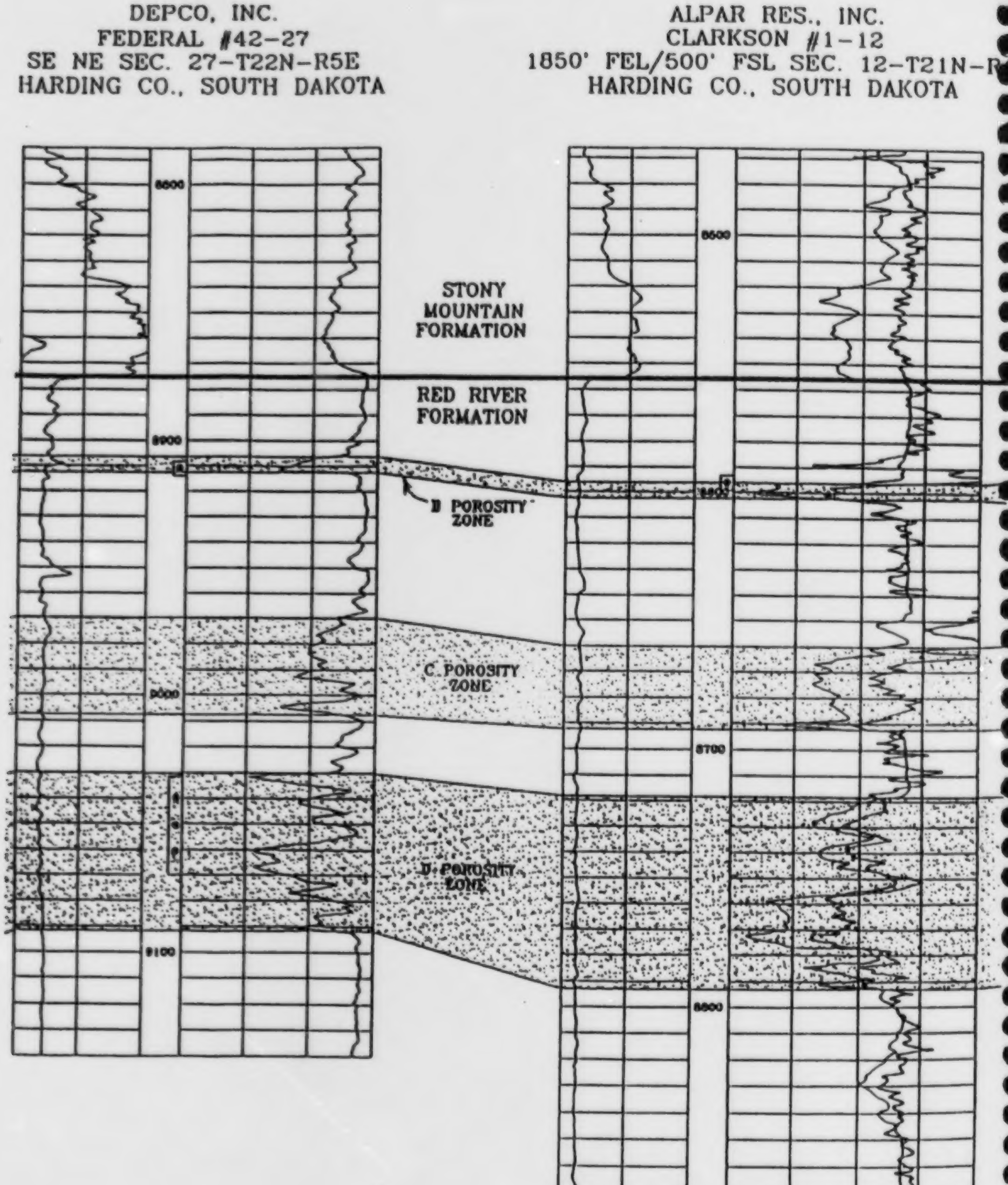


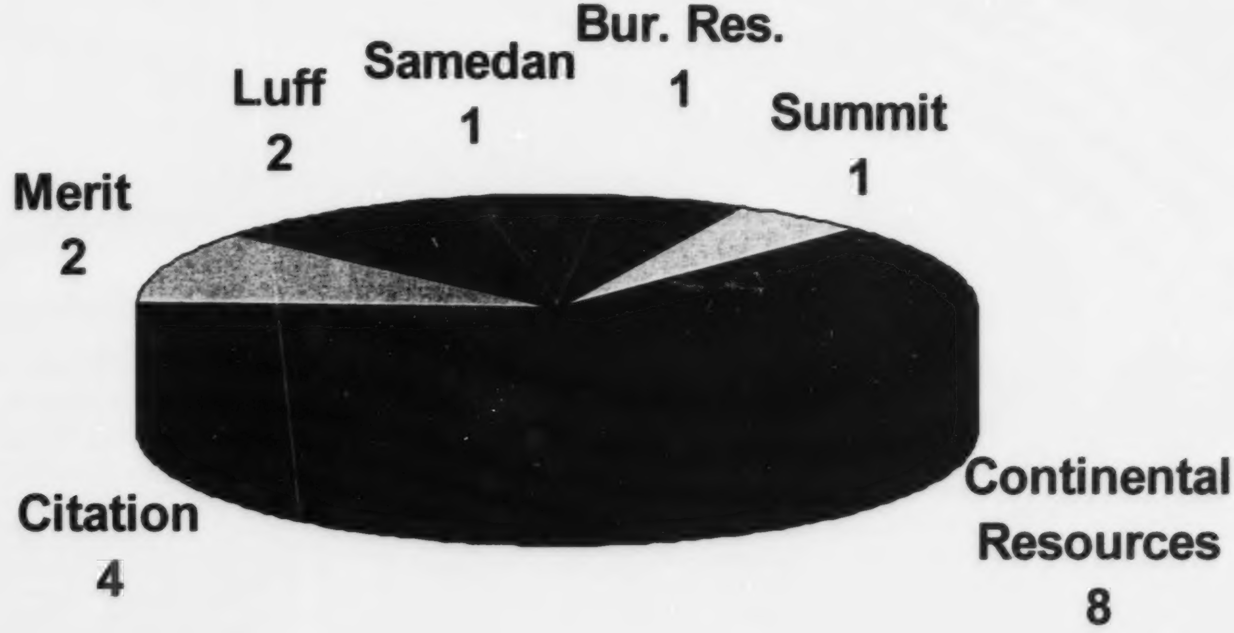
Figure 3 - Exhibit by Continental Resources, Inc. to SD Board of Minerals and Environment Hearing, 9/20/95.

Harding County Horizontal Wells 1988-1998

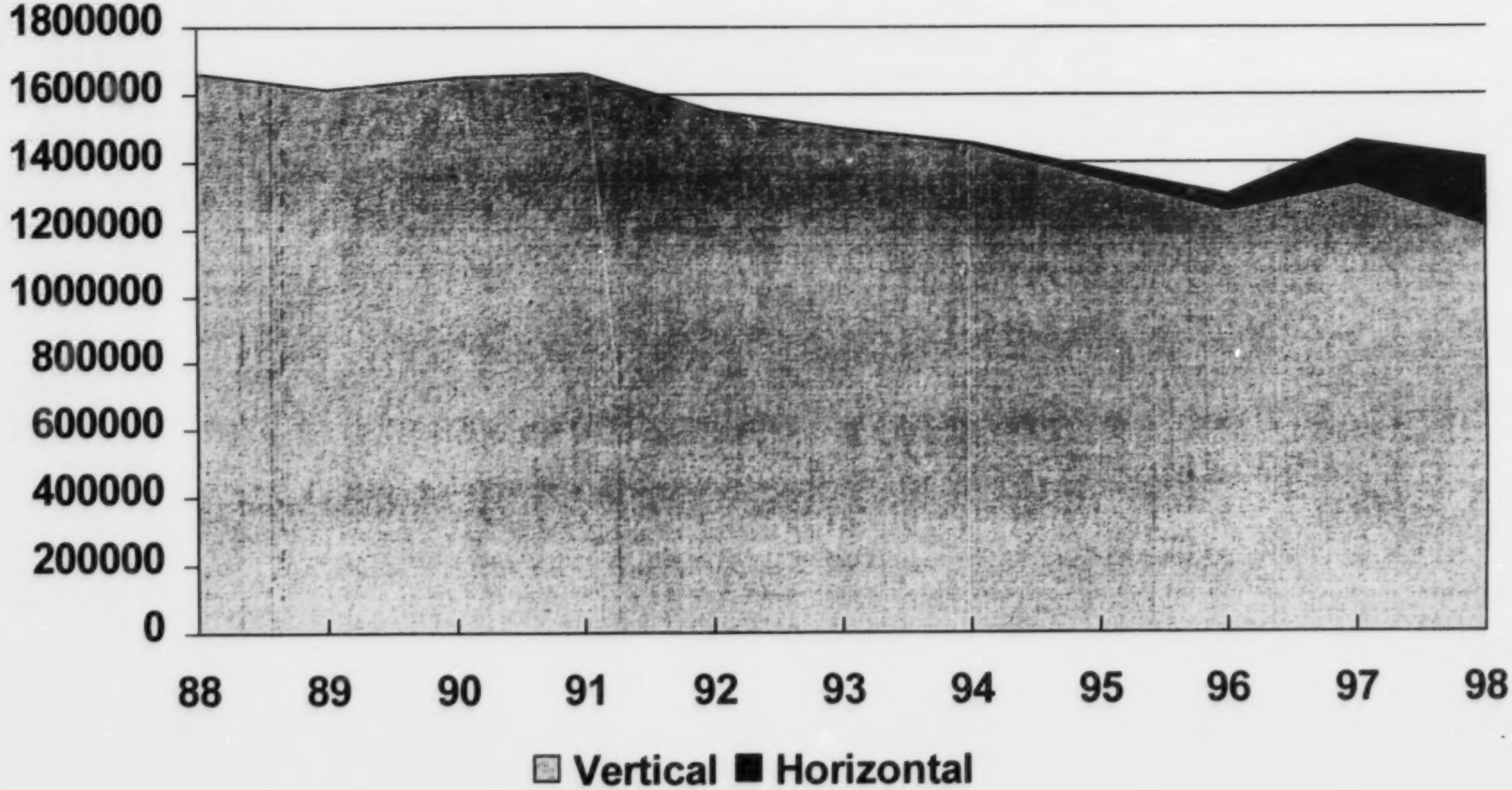
Well Name	Operator	Status	Spud Date	Depth	Lateral Length
14-30 E. Buffalo Fed	Meidian Oil Co.	P&A	12/16/88	TVD-9124, MD-10,086	962
12-22H WB'B'RRU	Citation Oil & Gas	Producer	9/25/94	TVD-8404,MD-11,200	2796
2-26H WB'B'RRU	Citation Oil & Gas	Injection (Water)	11/6/94	TVD-8422, MD-11,300	2878
41-27H Niemi	Merit Energy	TA	10/29/95	TVD-8324, MD-11,878	3554
1-11 JJ Ranch	Continental Resources	P&A	11/25/95	TVD-8714, MD-13,202	4488
14-15H State	Merit Energy	Producer	12/3/95	TVD-8857, MD-12,661	3804
41-5H Tedrow	Samedan Oil	P&A	7/12/96	TVD-8667, MD-13,127	4460
23-25H WBBRU/ 23-30H SBRRU	Continental Resources	Injection (Air)	9/11/96	TVD-8572, MD-13,406	4834
31-8H BRRU	Continental Resources	Producer	10/17/96	TVD-8524, MD-13,633	5109 (longest lateral)
44-16HI State	Citation Oil & Gas	Producer, re-entry	11/5/96	TVD-8444, MD-11,084	2640
M-20H Stearns	Luff Exploration	Injection (Water)	11/15/96	TVD-9040, MD-10,059	1019
6-21 Clarkson	Citation Oil & Gas	Producer, re-entry	11/23/96	TVD-8470, MD-9374	904
41-27H/44-22H SBRRU	Continental Resources	Producer	11/24/96	1:TVD-8330, MD-11,144	2814
				2:TVD-9042, MD-12,782	3740
1-19F Johnson Ranch	Continental Resources	Producer	1/19/97	TVD-9625, MD-12,031	2406
24-36H SBRRU	Continental Resources	Producer	3/1/97	1:TVD-8646, MD-13,303	4657
				2:TVD-8527, MD-12,806	4279
44-4H SBRRU	Continental Resources	Injection (Air)	8/8/97	TVD-8390, MD-11,836	3448
13-17H State	Summit Resources	TA	8/10/97	TVD-8073, MD-11,404	3331
1-7F Table Mountain	Continental Resources	Producer	9/10/97	1:TVD-8958, MD-11,003	2045
				S1:TVD-8935, MD-10,768	1833
				S2:TVD-8953, MD-11,012	2059
				2:TVD-8949, MD-11,592	2643
Luff 41-22 Otterness	Luff Exploration	Producer	10/12/98	TVD-9134, MD-9638	504

SD DENR Oil & Gas Program 3/22/99 Figure 4

South Dakota Horizontal Well Operators
19 Wells as of March 1999

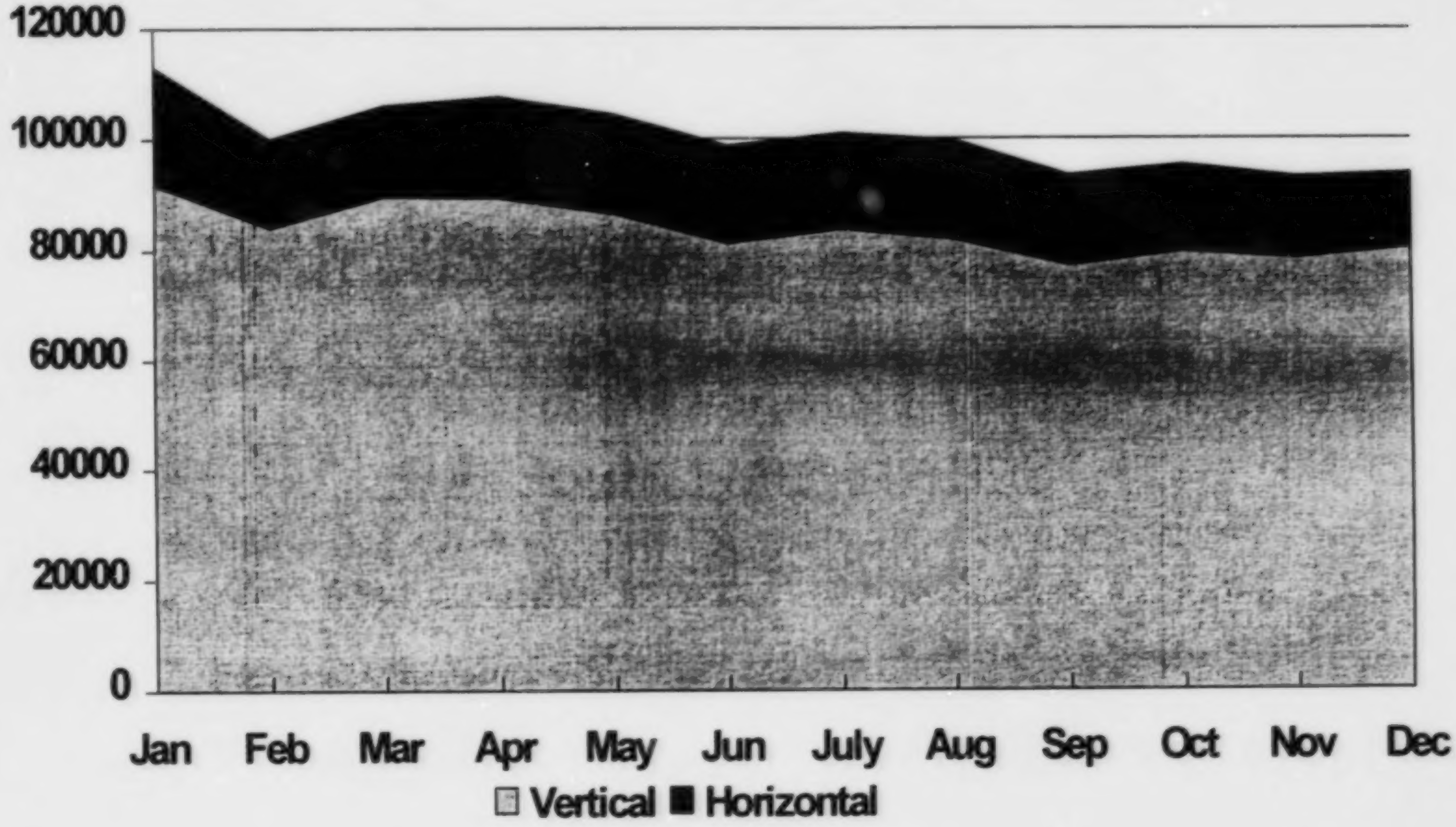


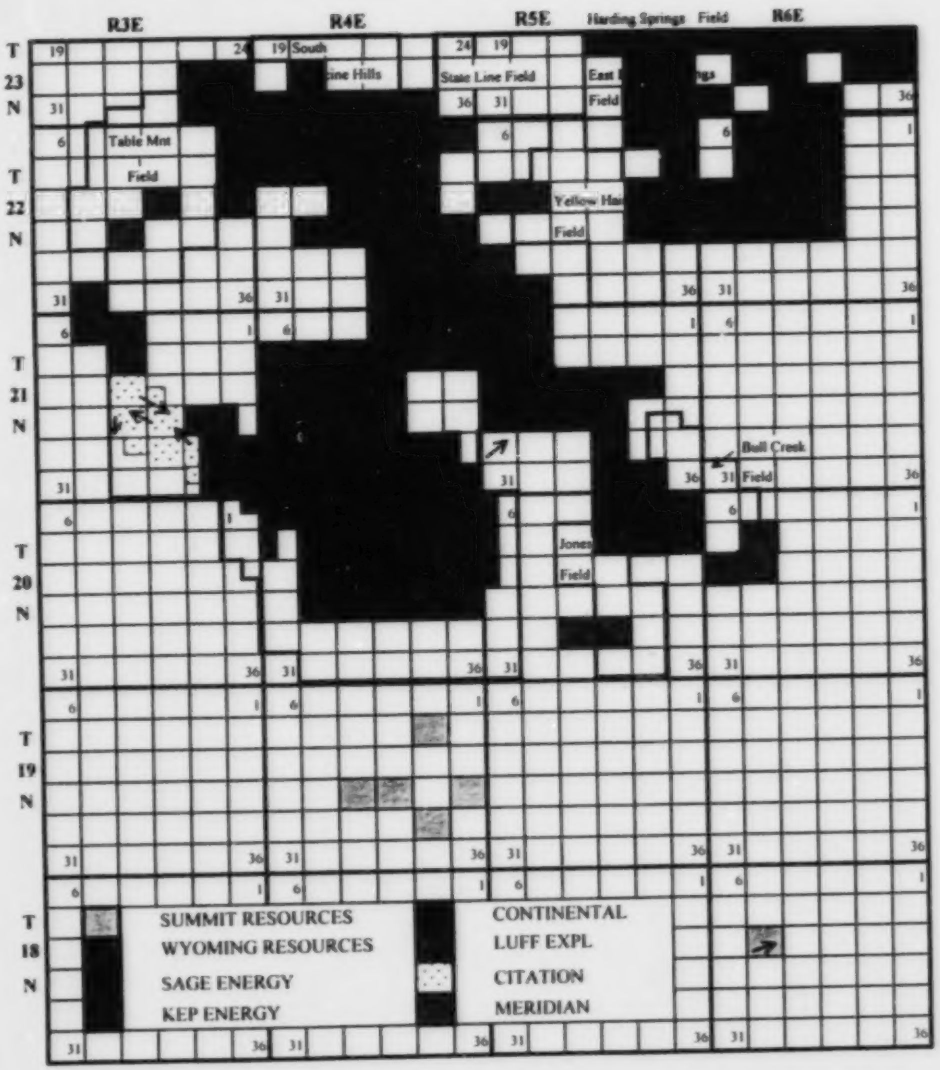
South Dakota 1988-1998
Yearly Oil Production (BBLS)



SD DENR - Oil & Gas Program 3/22/99 Figure 6

South Dakota 1998
Monthly Oil Production (BBLS)





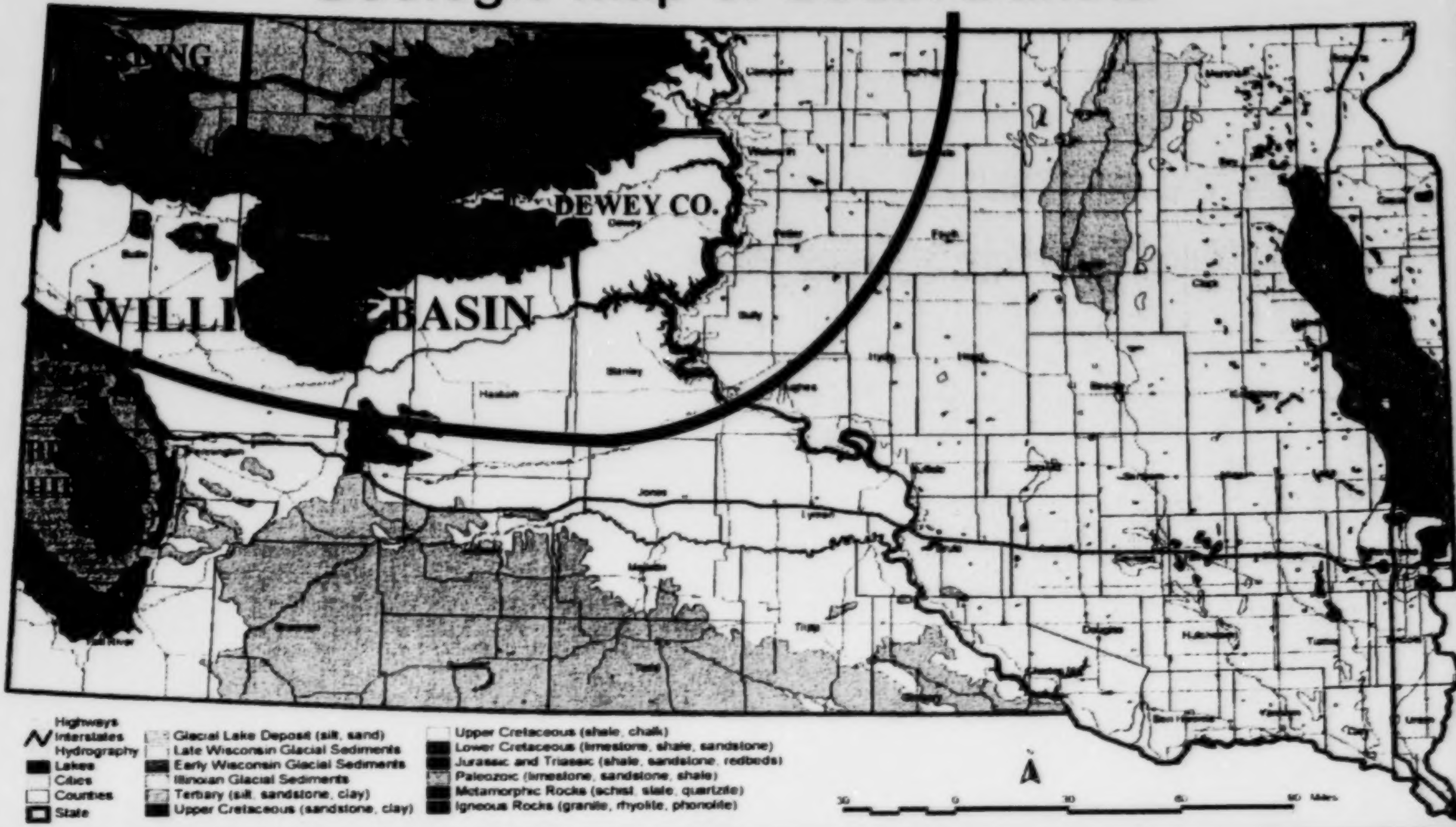
HORIZONTAL SPACING
IN HARDING COUNTY, SD

SD DENR
OIL & GAS PROGRAM
03/22/1999
Fig. 8

Notice of Recommendation Procedure

- Application is made and reviewed by DENR
- DENR publishes NOR, usually with conditions.
- Allow 20 days from publication date for comments.
- If no objections, O&G Supervisor approves the application administratively.
- If objections made, a hearing is scheduled before the Board of Minerals and Environment.

Geologic Map of South Dakota



SD DENR - Oil & Gas Program 3/22/99 Figure 10

7TH INTERNATIONAL WILLISTON BASIN HORIZONTAL WELL WORKSHOP

HORIZONTAL DRILLING ACTIVITY IN MANITOBA

Last year in Manitoba, 15* of the 41 wells drilled were horizontal. In 1998, horizontal wells accounted for 36.6% of the wells drilled and 57.8% of the drilling meterage in Manitoba, compared to the Western Canadian average of 11% of all completions. The average horizontal well depth was 1886 m, compared to 793 m for vertical wells. The average horizontal well took 11 days to drill and had a horizontal section length of 894 m.

Manitoba's leading horizontal drillers in 1998 were Tundra Oil and Gas Ltd. with 9 wells, followed by Search Energy Corp. with 5 wells and Mountcliff Resources with 1 well. During the first quarter of 1999, 4 of the 6 wells drilled in the Province were horizontal.

To date, horizontal wells have been drilled in 33 different pools in 10 of Manitoba's 13 fields. Horizontal wells are not only being used successfully as infill wells between existing producers, but also to develop newly discovered pools, extend existing pool boundaries and to produce trapped oil in mature waterfloods.

The Mission Canyon 3 Formation was the favourite target in 1998 with 6 wells drilled, followed by the Lodgepole with 5 wells. To date, the Lodgepole, MC-1 and MC-3 formations have been the target of 80 of the 91 horizontal wells drilled in Manitoba.

Horizontal well production has increased annually since 1992. In 1998, horizontal well production increased by 34% to 183,047 m^3 (1 151 895 bbls). In December 1998, 73 of the 91 horizontal wells drilled in Manitoba were on production. Production from these wells totaled 546.7 m^3/d (3440 b/d), an average of 7.5 $m^3/d/well$ (47 b/d/well) and represented 33.3% of the provincial total. By comparison the average vertical well in Manitoba produces 1.0 m^3/d (6.3 b/d).

---

* includes one horizontal re-entry

Lodgepole and MC-3 horizontal producers accounted for 75% of horizontal well production in 1998. Horizontal producers located in the Pierson, Virden, Tilston and Daly Fields accounted for 81.9% of horizontal well production.

Normalized production for horizontal wells in Manitoba, determined by setting each well back to the same "time-zero", is characterized by a decline rate of 58.2% in the first 12 months from an initial rate of 16.1 m^3/d (101 b/d), followed by a decline of 17.4% for the remainder of the well's life. Based on the limited production history for most Manitoba horizontal wells, the majority of which have produced for less than five years, the average well is likely to recover 20 778 m^3 (130,750 bbls).

In Manitoba, a horizontal well is defined as a well that achieves an angle of at least 80° from the vertical for a minimum distance of 100 m. To drill a horizontal well in Manitoba no special approval is required, only a well licence. Horizontal wells receive a HOV of 10 000 m^3 (62,930 bbls) or 10 years production, whichever comes first. Production from horizontal wells is classified as new oil. The value of the horizontal well incentive based on initial productivity of 15 m^3/d (94 b/d) and 20 m^3/d (126 b/d) both declined at 30% p.a. (exponential) is shown below.

Well Classification	Oil Price ($/m³)	HOV (m³)	Initial Production (m³/d)	Value of Holiday Oil Volume	
				Crown Royalty	Production Tax
Horizontal	160	10000	15.0	$ 287,636	$ 190,178
Horizontal	160	10000	20.0	$ 323,538	$ 230,783

Where a horizontal well penetrates or drains more than one spacing unit, royalty and production tax is calculated per spacing unit based on production allocated to the spacing unit. The saving associated with paying royalty and production tax for a horizontal well, on a per spacing unit basis should not be overlooked. From the previous example, a well with initial productivity of 20 m^3/d (126 b/d) declined at 30% p.a. (exponential) will be producing 12.1 m^3/d (76 b/d) after production of the 10 000 m^3 (62,930 bbls) HOV. The Crown royalty rate on total well production would equal

22.8%, compared to 18.9% where the well penetrates or drains three spacing units and 16.9% where four spacing units are penetrated or drained. This translates into monthly royalty savings of $2295 for the three spacing unit case and $3472 for the four spacing unit case. Production tax savings of $2615 and $3936 per month are realized under the same conditions.

In 1999, the Manitoba Government approved the implementation of reductions in Crown royalties and freehold production taxes payable by oil and gas producers. The new "Third Tier Oil " is oil produced from a vertical well drilled or re-entered on or after April 1, 1999, oil produced from an inactive vertical well, activated after April 1, 1999 or, oil produced from an "old oil well" or "new oil" well that, in the opinion of the Director, can be reasonably attributed to an increase in reserves from an enhanced recovery project implemented under The Oil and Gas Act after April 1, 1999.

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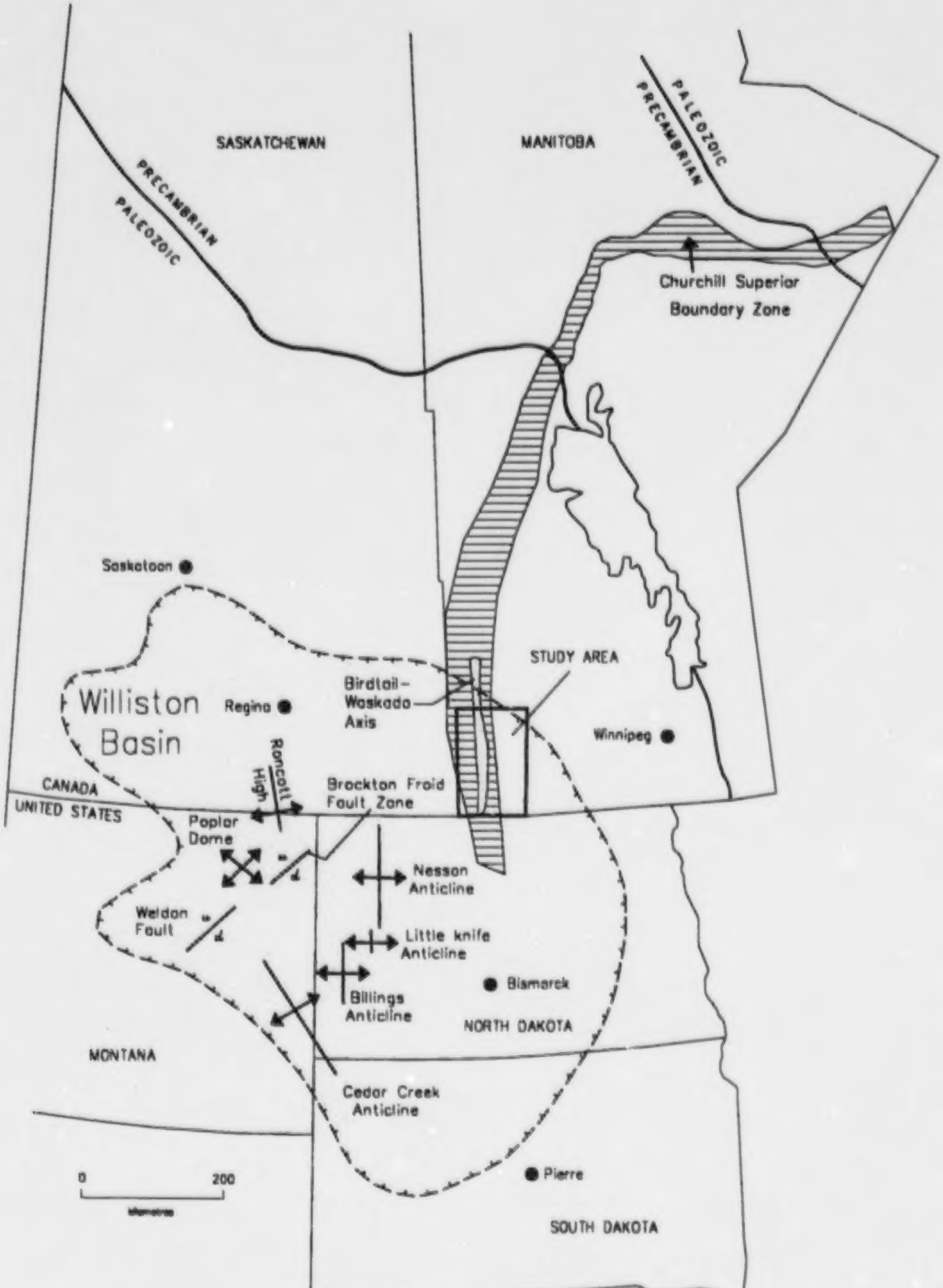
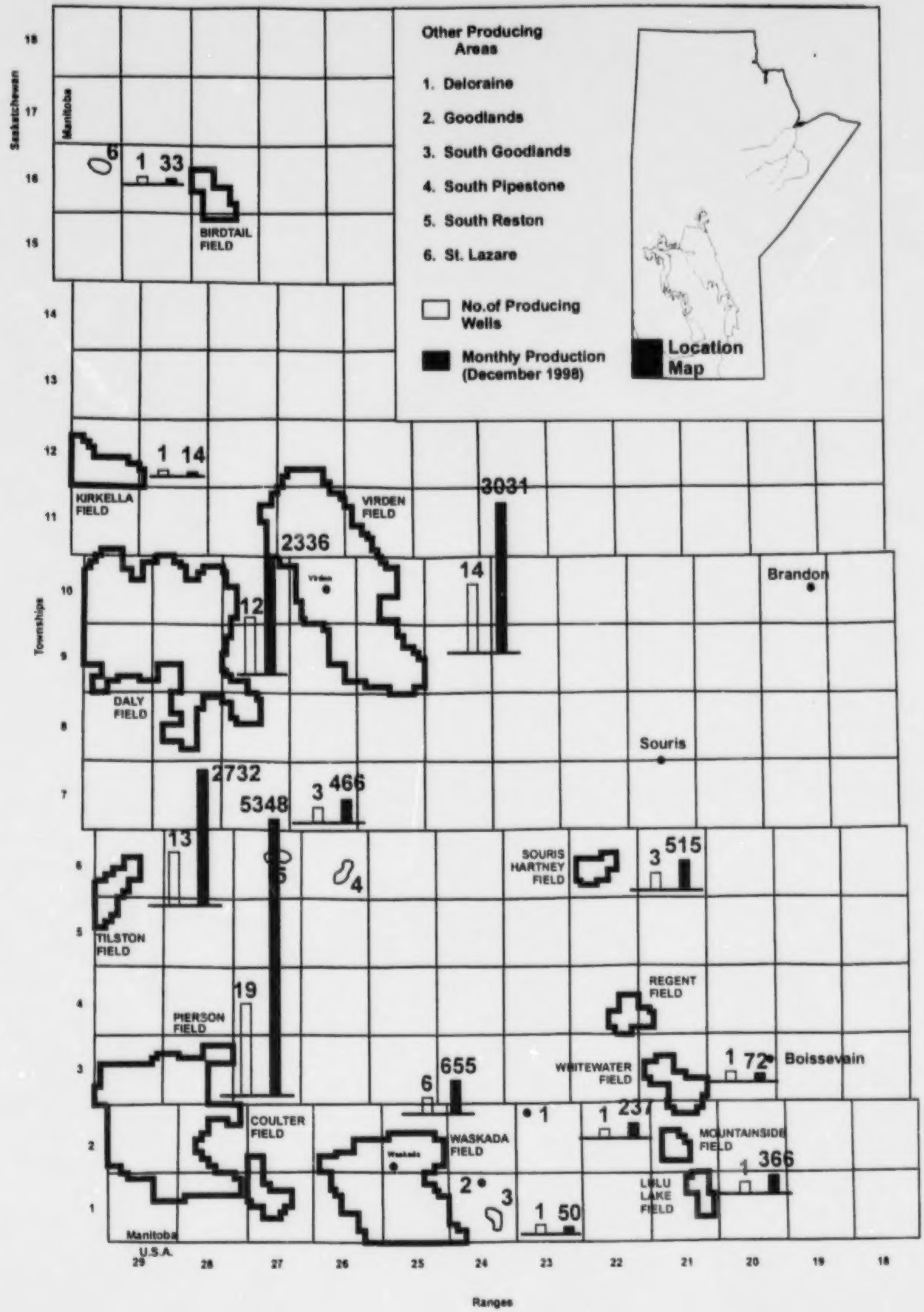


Map of the Williston Basin showing major structural features and study area for the Branch's soon to be released report: Regional Overview of the Geology and Petroleum Potential, Mission Canyon Formation (MC-1 Member), Southwestern Manitoba.



Other Producing Areas
1. Deloraine
2. Goodlands
3. South Goodlands
4. South Pipestone
5. South Reston
6. St. Lazare
No.of Producing Wells
Monthly Production (December 1998)
Location Map
Saskatchewan
Manitoba
BIRDTAIL FIELD
KIRKELLA FIELD
VIRDEN FIELD
Virden
DALY FIELD
Brandon
Souris
TILSTON FIELD
SOURIS HARTNEY FIELD
REGENT FIELD
PIERSON FIELD
WHITEWATER FIELD
Boissevain
COULTER FIELD
WASKADA FIELD
Waskada
MOUNTAINSIDE FIELD
LULU LAKE FIELD
Manitoba
U.S.A.
1 33
1 14
3031
2336
14
12
2732
5348
3 466
13
3 515
19
1 72
6 655
1 237
1
2
3
1 50
1 366
Townships
18
17
16
15
14
13
12
11
10
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Ranges
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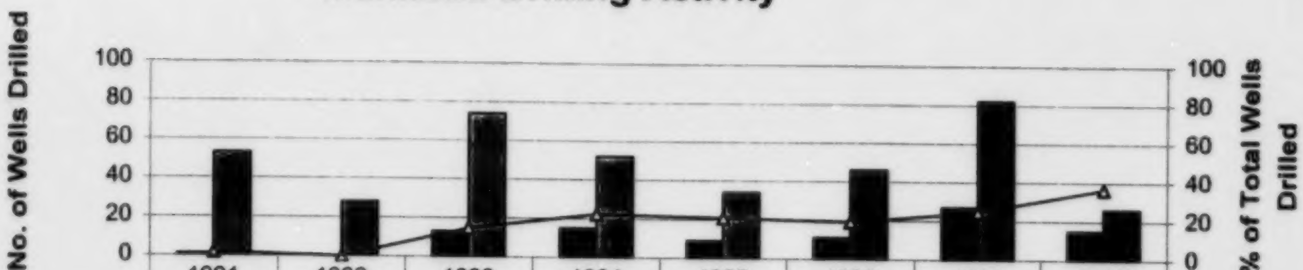
21
20
19
18

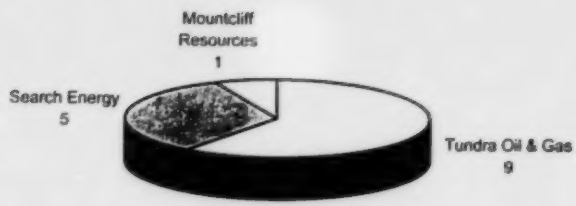
Manitoba Drilling Activity



	1991	1992	1993	1994	1995	1996	1997	1998
Horizontal Wells	1	0	13	15	9	11	27	15
Vertical Wells	53	28	74	52	34	46	82	26
% of Total Wells Drilled	1.9	0	14.9	22.4	20.9	19.3	24.8	36.6

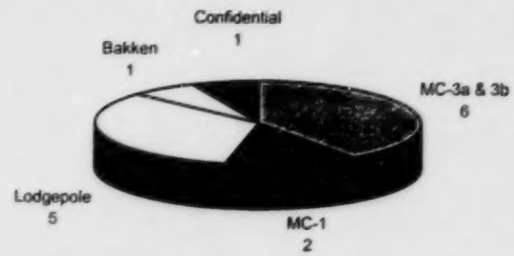
Year

1998 Horizontal Drilling By Operator



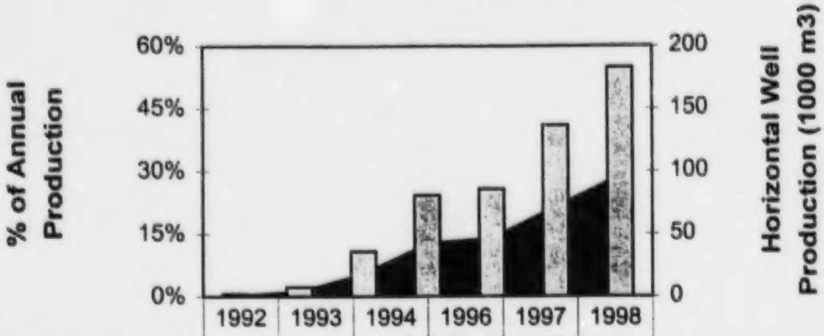
15 Horizontal Wells Drilled

1998 Horizontal Drilling By Formation



15 Horizontal Wells Drilled

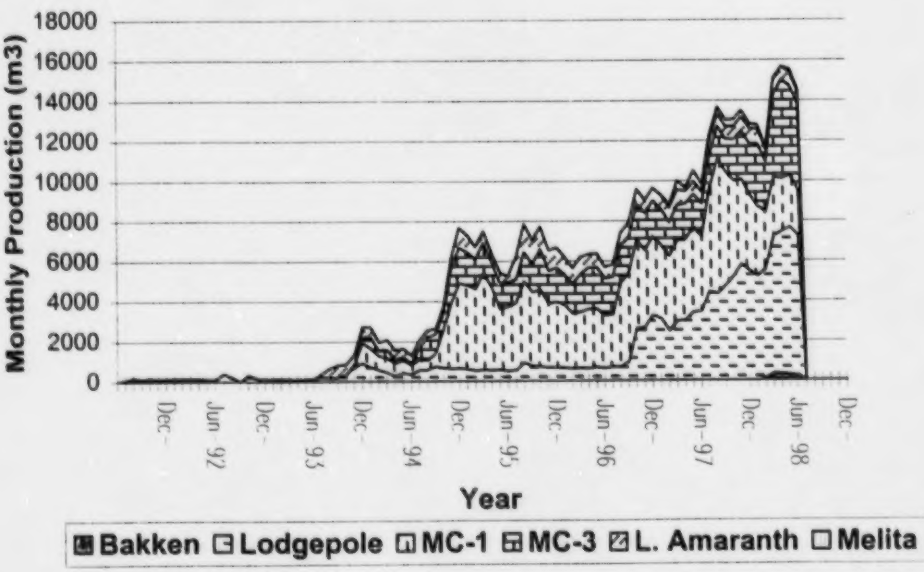
Horizontal Well Production



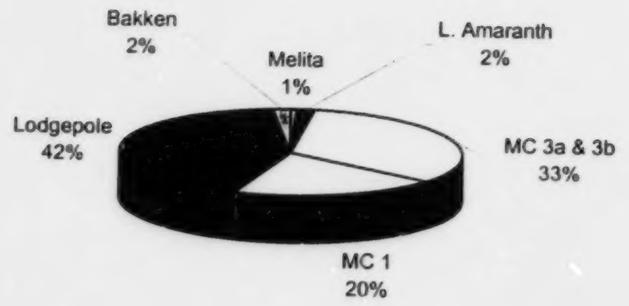
	1992	1993	1994	1996	1997	1998
■ % of Manitoba Production	0.3%	1.2%	5.5%	14.0%	21.4%	28.9%
□ Horizontal Well Production (103m3)	2.1	7.6	36.1	85.7	136.4	183.1

Year

Horizontal Well Production By Formation

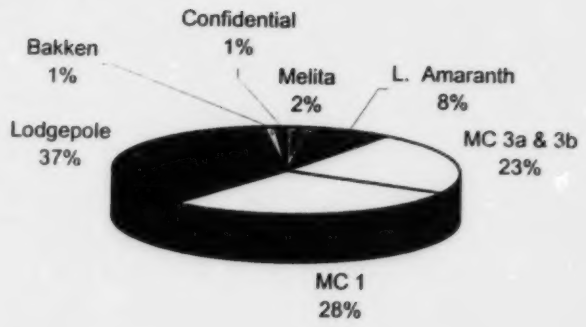


1998 Production by Formation



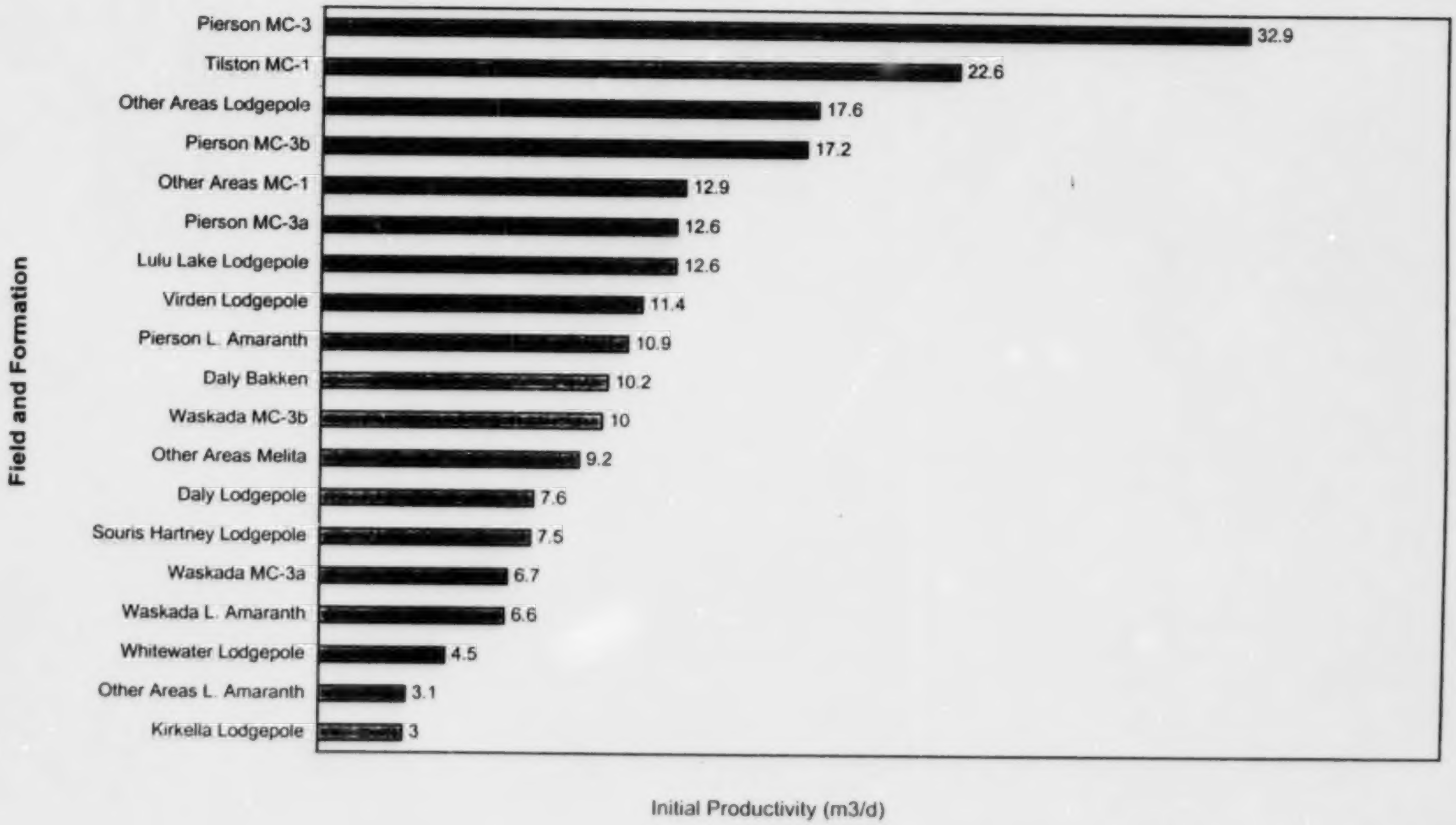
Total Production: 183 047 m3

Horizontal Drilling Targets 1991-98



91 Horizontal Wells Drilled

Initial Horizontal Well Productivity By Field and Formation



Normalized Horizontal Well Production

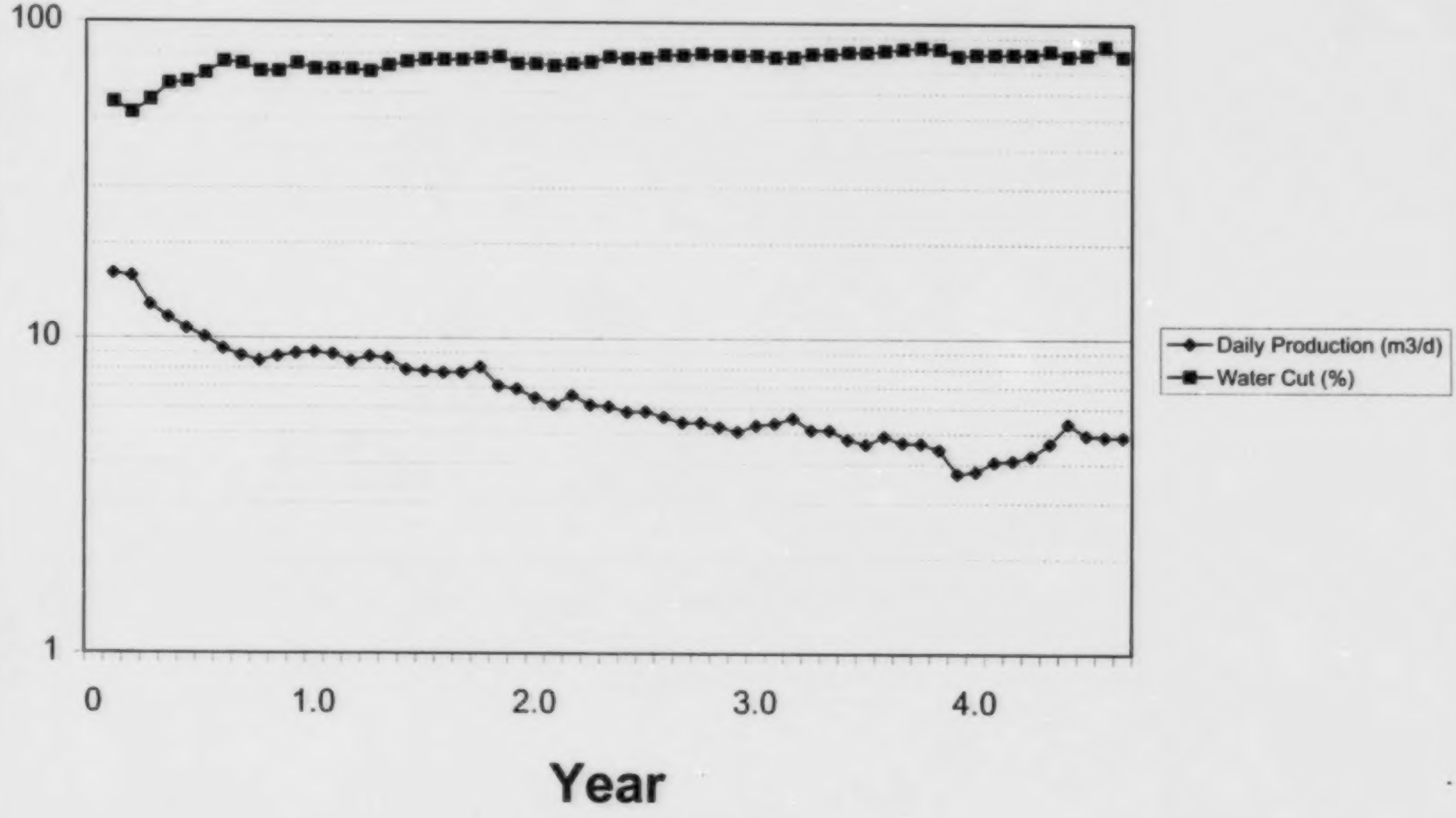


Table 1 - Horizontal Well Production Summary

Formation	No. Of Wells Drilled	Cumulative Production (31-Dec-98) (m3)	Average Initial Productivity 1st (6) Months (m3/d)	No. of Wells On Production Dec-98	Daily Production Dec-98 (m3/d)	Daily Production per Well Dec-98 (m3/d/well)	Average Measured Depth (m)	Average Hzntl. Section Length (m)
Melita	2	4900.7	9.2	1	2.2	2.2	912	374
L. Amaranth	7	42824.3	9.2	6	19.1	3.2	2426	1290
MC 3a & 3b	20	126769.8	18.0	18	201.4	11.2	1843	756
MC 1	26	190661.4	18.6	17	109.9	6.5	1578	606
Lodgepole	34	163556.9	9.0	30	207	6.9	1434	649
Bakken	1	2816.5	10.2	1	7.1	7.1	1770	851
Confidential	1	—	—	—	—	—	1480	395
Total	91	531529.6	13.6	73	546.7	7.5	1634	703

1998 HORIZONTAL WELL PRODUCTION SUMMARY

Mar. 1/99

PRODUCING FORMATION	WELL	LICENSEE	PRODUCING POOL	MD (m)	HORIZONTAL SECTION LENGTH (m)	INITIAL PRODUCTIVITY 1ST 6 MONTHS OR LESS (m3/d)	DAILY PRODUCTION Dec/98 (m3/d)	CUMULATIVE PRODUCTION Dec/98 (m3)	STATUS
Melita	4-22-16-29	Renaissance Energy	Other Areas Melita A	796	277	10.5	SI	2079.0	COOP
	A4-22-16-29	Renaissance Energy	Other Areas Melita A	784	226	7.8	2.2	2821.7	COOP
		2nd Leg	KOP-610 m	854	244				
Lower Amaranth	7-15-2-29	Home Oil	Pierson L. Amaranth-MC 3b A	1871	624	4.3	-	-	COOP
		2nd leg	KOP-1492 m	1805	313				
		3rd leg*	KOP-1270 m	1829	559	7.0	3.1	5 707.2	
	11-11-2-29	Home Oil	Pierson L. Amaranth-MC 3b A	2465	1283	15.5	5.3	15 543.4	COOP
	2-26-1-29	Williston Wildcatters	Pierson - L. Amaranth L	1652	408	-	-	0.4	ABD PROD
	11-10-2-29	Home Oil	Pierson L. Amaranth-MC 3b A	1838	692	10.9	2.4	6 459.0	COOP
	9-25-1-26	NCE Petrofund	Waskada L. Amaranth A	1703	675	6.6	1.9	3 494.8	COOP
		2nd leg	KOP-1086 m	1675	589				
	2-19-2-29	Home Oil	Pierson L. Amaranth-MC 3b A	2481	1353	16.8	4.8	10 706.6	COOP
		2nd leg	KOP-1164 m	[illegible]	816				
	4-15-1-24	Tundra Oil and Gas	Other Areas L. Amaranth I	2216	1237	3.1	1.6	912.9	COOP
		2nd leg	KOP-1011 m	1490	479				
Mission Canyon 3	1-16-2-29	Home Oil	Pierson L. Amaranth-MC 3b A	1709	586	14.2	1.6	4 986.0	COOP
	5-30-1-28	Rideau Petroleums	Pierson - MC 3	1360	218	-	-	-	COMP
		2nd leg	KOP-1156 m	1397	241				
	5-3-2-26	NCE Petrofund	Waskada MC 3b B	1624	600	12.0	2.3	7 006.4	COOP
	12-5-3-28	Home Oil	Pierson MC 3b B	1494	415	7.0	SI	1 464.9	COOP
	1-26-1-26	NCE Petrofund	Waskada MC 3a A	1811	788	6.5	1.6	3 681.6	COOP
	14-34-1-26	NCE Petrofund	Waskada MC 3b B	1581	543	8.0	1.4	4 229.2	COOP
	10-35-1-26	NCE Petrofund	Waskada MC 3a I	1410	368	6.8	3.9	5 174.2	COOP
		2nd leg	KOP-1341 m	1587	246				

*3rd leg on Production July 26, 1995, 1st & 2nd leg on Production June 28, 1993

1998 HORIZONTAL WELL PRODUCTION SUMMARY

Mar. 1/99

PRODUCING FORMATION	WELL	LICENSEE	PRODUCING POOL	MD (m)	HORIZONTAL SECTION LENGTH (m)	INITIAL PRODUCTIVITY 1ST 6 MONTHS OR LESS (m3/d)	DAILY PRODUCTION Dec/98 (m3/d)	CUMULATIVE PRODUCTION Dec/98 (m3)	STATUS
Mission Canyon	3-18-3-28	Tundra Oil and Gas	Pierson MC 3b B	1877	791	25.8	7.2	22 979.1	COOP
3	7-11-3-29	Tundra Oil and Gas	Pierson MC 3a C	1215	127	4.9	-	-	COOP
		2nd leg	KOP-1094 m	1697	603				
		3rd leg**	KOP- 1215 m	1820	605	5.5	2.8	4 021.2	
	A3-18-3-28	Tundra Oil and Gas	Pierson MC 3b B	1888	820	21.8	20.4	21 412.8	COOP
	11-17-3-28	Tundra Oil and Gas	Pierson MC 3a B	2003	945	15.5	7.0	11 774.6	COOP
	3-22-3-28	Todd Ballantyne	Pierson MC 3a B	1658	561	0.7	0.7	341.6	COOP
	11-6-3-29	Search Energy	Pierson MC 3 C	1605	440	18.5	2.4	4 246.8	COOP
		2nd leg	KOP-1170 m	1464	294				
	5-12-3-29	Tundra Oil and Gas	Pierson MC 3a C	1844	763	26.7	20.4	8 525.1	COOP
	12-6-3-29	Search Energy	Pierson MC 3 C	1537	402	44.5	17.1	10 139.3	COMP
		2nd leg	KOP-1154 m	1511	357				
	A5-12-3-29	Tundra Oil and Gas	Pierson MC 3a C	1286	195	22.5	19.1	3 423.1	COOP
		2nd leg	KOP – 1164 m	1966	802				
	A11-6-3-29	Search Energy	Pierson MC 3 C	1568	430	42.7	35.1	7 577.2	COOP
		2nd leg	KOP – 1152 m	1605	453				
	6-6-3-29	Search Energy	Pierson MC 3C	1558	446	19.7	10.5	3 537.2	COOP
	8-12-3-29	Tundra Oil and Gas	Pierson MC 3b B	1759	691	17.3	9.0	1 899.7	COOP
		2nd leg	KOP – 1275	1856	581				
	14-6-3-29	Search Energy	Pierson MC 3 C	1384	300	38.9 (1 month)	38.9	349.8	COOP
		2nd leg	KOP 1100 m	1343	243				
Mission Canyon	1-8-6-29	Tundra Oil and Gas	Tilston MC 1 C	1680	570	26.7	2.5	18 054.7	COOP
1	A1-8-6-29	Tundra Oil and Gas	Tilston MC 1 C	1724	691	26.8	11.4	36 754.9	COOP
	2-8-6-29	Tundra Oil and Gas	Tilston MC 1 C	1864	756	33.3	6.3	27 776.9	COOP
		2nd leg	KOP-1282 m	1657	375				
	3-31-5-29	Pinnacle Resources	Tilston MC 1 A	1628	580	13.9	0.9	4 126.9	COOP
		2nd leg	KOP-1082 m	1584	502				
	6-8-6-28	Pinnacle Resources	Other Areas - MC 1 E	1554	495	14.5	SI	5 964.1	COOP

**3rd leg on Production Sep. 20,1996, 1st & 2nd leg on Production Sep. 14, 1995

1998 HORIZONTAL WELL PRODUCTION SUMMARY

Mar. 1/99

PRODUCING FORMATION	WELL	LICENSEE	PRODUCING POOL	MD (m)	HORIZONTAL SECTION LENGTH (m)	INITIAL PRODUCTIVITY 1ST 6 MONTHS OR LESS (m3/d)	DAILY PRODUCTION Dec/98 (m3/d)	CUMULATIVE PRODUCTION Dec/98 (m3)	STATUS
Mission Canyon 1	12-15-6-29	Tundra Oil and Gas	Tilston MC 1 C	1335	328	22.5	2.2	11 419.4	COOP
	12-32-5-29	Pinnacle Resources	Tilston MC 1 A	1538	485	14.7	0.4	3 945.9	COOP
	11-6-6-28	Pinnacle Resources	Other Areas - MC 1 E	1424	778	3.9	SI	831.7	COOP
	A3-31-5-29	Pinnacle Resources	Tilston MC 1 A	1463	412	5.4	0.7	1 327.0	COOP
	10-31-5-29	Pinnacle Resources	Tilston MC 1 A	1763	697	8.3	0.8	2 533.0	COOP
	11-15-6-29	Tundra Oil and Gas	Tilston MC 1 C	1123	125	27.0	4.7	15 675.6	COOP
		2nd leg	KOP-1048 m	1378	330				
	B1-8-6-29	Tundra Oil and Gas	Tilston MC 1 C	1732	697	29.6	7.7	15 841.9	COOP
	12-9-6-29	Tundra Oil and Gas	Tilston MC 1 C	1284	289	36.4	5.9	13 838.4	COOP
		2nd leg	KOP-1052 m	1238	186				
		3rd leg	KOP-1137 m	1630	493				
	8-14-6-27	CanNat Resources	Other Areas MC 1 H	1780	789	13.9	7.6	6 861.8	COOP
	2-16-6-26	CanNat Resources	Other Areas MC 1 G	1067	247	9.6	SI	3 197.2	COOP
		2nd leg.	KOP-960 m	1229	269				
	6-14-6-27	CanNat Resources	Other Areas MC 1 H	1649	738	12.3	6.5	4 703.0	COOP
	14-9-6-26	Rigel Oil & Gas	Other Areas MC 1 G	1355	463	38.7	3.8	7 225.4	COOP
	15-16-6-26	CanNat Resources	Other Areas MC 1 G	1700	837	10.9	3.1	3 344.8	COOP
	3-9-6-26	Rigel Oil & Gas	Other Areas	1390	332	-	-	-	COMP
	RE13-4-6-26	Rigel Oil & Gas	Other Areas	1293	394	-	-	-	WOSR
	A14-9-6-26	Rigel Oil & Gas	Other Areas MC1 G	1270	395	0.5	SI	109.0	COOP
	4-16-6-26	CanNat Resources	Other Areas MC 1 G	1299	459	11.8	SI	1 087.2	COOP
	11-9-6-26	Rigel Oil & Gas	Other Areas	1248	224	-	-	-	COMP
	C1-8-6-29	Tundra Oil and Gas	Tilston MC 1 C	1481	464	17.2	16.0	2 388.9	COOP
		2nd leg	KOP – 1127 m	1690	563				
	5-15-6-29	Tundra Oil and Gas	Tilston MC 1 C	1576	590	31.5	29.4	3 653.7	COOP
	5-32-5-26	Rigel Oil & Gas	Other Areas	1073	191	-	-	-	COMP

1998 HORIZONTAL WELL PRODUCTION SUMMARY

Mar. 1/99

PRODUCING FORMATION	WELL	LICENSEE	PRODUCING POOL	MD (m)	HORIZONTAL SECTION LENGTH (m)	INITIAL PRODUCTIVITY 1ST 6 MONTHS OR LESS (m3/d)	DAILY PRODUCTION Dec/98 (m3/d)	CUMULATIVE PRODUCTION Dec/98 (m3)	STATUS
Lodgepole	8-30-10-28	Tundra Oil and Gas	Daly Lodgepole E	1220	331	5.4	2.5	10 058.3	COOP
	5-18-12-29	Neutrino Resources	Kirkella Lodgepole Daly C	885	104	2.7	-	651.5	SWD
	6-17-12-29	Neutrino Resources	Kirkella Lodgepole Daly B	1219	455	3.0	-	515.2	SWD
	5-17-12-29	Neutrino Resources	Kirkella Lodgepole Daly B	1320	523	3.3	0.5	1 093.6	COOP
	7-22-9-29	Rideau Petroleums	Daly Lodgepole D	1338	472	2.1	0.6	1 546.6	COOP
	14-22-8-28	Herc Oil	Daly Lodgepole O	1584	621	1.4	SI	461.6	COOP
		2nd leg	KOP-874 m	1366	492				
	3-17-6-22	Tundra Oil and Gas	Souris Hartney Lodgepole Virden A	1543	816	10.3	9.1	19 655.6	COOP
	15-17-6-22	Tundra Oil and Gas	Souris Hartney Lodgepole Virden A	1359	612	4.8	1.7	4 816.2	COOP
	6-33-8-28	Herc Oil	Daly Lodgepole Q	1197	321	2.6	SI	83.1	COOP
	14-16-6-22	Tundra Oil and Gas	Souris Hartney Lodgepole Virden A	1386	634	7.4	5.8	8 092.6	COOP
	3-20-11-26	Upton Resources	Virden Lodgepole A	1271	499	4.7	4.2	3 758.8	COOP
	6-26-11-26	Chevron Canada	Virden Lodgepole A	1135	461	-	-	-	J&A
		2nd leg	KOP-677 m	1102	425	5.2	3.6	3 382.6	COOP
	7-33-11-26	Chevron Canada	Virden Lodgepole A	1118	390	27.7	20.5	22 119.0	COOP
	12-34-11-26	Chevron Canada	Virden Lodgepole A	1138	411	11.2	2.9	5 312.9	COOP
	13-29-10-28	Tundra Oil and Gas	Daly Lodgepole E	1390	542	15.4	7.3	10 404.4	COOP
		2nd leg	KOP-873 m	1520	647				
	4-11-10-28	Chevron Canada	Daly Lodgepole A	1555	678	3.4	3.7	3 772.7	COOP
	15-2-10-28	Chevron Canada	Daly Lodgepole A	1551	667	7.4	5.5	4 930.8	COOP
	13-15-11-26	Chevron Canada	Virden Lodgepole A	1383	623	9.1	5.3	5 280.4	COOP
	11-16-2-21	Enron Oil	Other Areas Lodgepole WL E	1451	373	17.6	7.6	6 345.6	COOP
	4-2-3-21	Enron Oil	Whitewater Lodgepole WL B	1440	553	4.5	2.3	1 812.0	COOP
	1-20-9-25	Chevron Canada	Virden Lodgepole C	1207	540	8.6	6.9	2 792.6	COOP
	3-12-10-28	Chevron Canada	Daly Lodgepole A	1155	400	1.9	1.2	661.1	COOP
	15-12-10-28	Chevron Canada	Daly Lodgepole A	1159	409	6.2	3.8	2 214.4	COOP
	1-31-9-28	Chevron Canada	Daly Lodgepole A	1238	428	2.2	0.7	568.5	COOP
	16-30-11-26	Mountcliff Resources	Virden Lodgepole A	1465	755	20.5	14.1	5 500.2	COOP
		2nd leg	KOP-755 m	1131	376				

1998 HORIZONTAL WELL PRODUCTION SUMMARY

Mar. 1/99

PRODUCING FORMATION	WELL	LICENSEE	PRODUCING POOL	MD (m)	HORIZONTAL SECTION LENGTH (m)	INITIAL PRODUCTIVITY 1ST 6 MONTHS OR LESS (m3/d)	DAILY PRODUCTION Dec/98 (m3/d)	CUMULATIVE PRODUCTION Dec/98 (m3)	STATUS
Lodgepole	13-26-1-21	Tundra Oil and Gas	Lulu Lake Lodgepole WL B	1912	806	12.6	13.7	4 228.5	COOP
		2nd leg	KOP-1425 m	1903	478				
	3-4-12-26	Chevron Canada	Virden Lodgepole A	1156	534	6.1	4.5	2 306.1	COOP
	15-6-11-25	Chevron Canada	Virden Lodgepole B	1095	505	1.7	0.9	582.9	COOP
	15-22-11-26	Chevron Canada	Virden Lodgepole A	1303	671	7.5	5.9	3 164.3	COOP
	10-25-10-26	Chevron Canada	Virden Lodgepole B	1275	660	24.5	9.4	7 615.0	COOP
	12-13-10-28	Chevron Canada	Daly Lodgepole A	1417	644	6.2	5.0	2 231.7	COOP
	5-30-10-28	Tundra Oil and Gas	Daly Lodgepole E	1905	1103	36.9	38.2	11 928.4	COOP
	16-19-11-26	Tundra Oil and Gas	Virden Lodgepole A	1323	583	11.9	11.7	3 406.8	COOP
		2nd leg	KOP-792 m	1689	897				
	15-29-9-25	Tundra Oil and Gas	Virden Lodgepole C	1333	641	9.5	7.9	2 260.9	COOP
Bakken	6-33-10-29	Tundra Oil and Gas	Daly Bakken A	1770	851	10.2	7.1	2 816.5	COOP
Confidential	14-5-3-29	Search Energy	Confidential until Jun-99	1184	99	---	---	---	COOP
		2nd leg	KOP – 1088 m	1384	296				

NORTH DAKOTA HORIZONTAL UPDATE

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Horizontal activity remained strong during the first half of 1998 in North Dakota, but the prolonged effect of depressed oil prices won out and activity was crippled by the end of the year. Monthly horizontal production rates declined throughout the year, losing 4,800 bopd (765 cmopd) by the end of the year. Production from horizontal wells in December, 1998, averaged approximately 20,800 bopd (3,310 cmopd), accounting for 22% of North Dakota's production, although only 14% of the producing wells are horizontal.

The horizontal rig activity remained high until mid-year when activity rapidly declined. We started the year with 13 rigs on horizontal wells, by mid-year the count was 10 and in December, 1998, the count was only 2. The average rig count for 1998 was 7. Rig activity will probably remain extremely low until the price of oil rebounds significantly. A total of 82 horizontal wells were drilled during the year and 76 were completed as producers for a success rate of 93%. It appears that the level of activity in 1999 will remain below that generated in 1998.

We issued 62 permits in 1998. The **Madison** Group accounted for 50 permits and the **Red River** Formation accounted for 7 permits. Numerous renewals were issued throughout the year, mainly for **Red River** wells to be drilled in Slope and Bowman Counties.

A total of 36 wells were drilled to the **Red River** Formation in North Dakota during 1998, of which 33 wells were completed as producers for a success ratio of 92%. Thirty-one wells were drilled in Bowman County, 3 in Slope County and 1 in both Divide and Golden Valley Counties. Production from Bowman County is from a depth of approximately 9,100 feet (2,770 meters). The average **Red River** horizontal well takes 33 days from spud to total depth, has an open hole lateral section of 4,760 feet (1,450 meters), with an initial average production rate of 166 bopd (26 cmopd). The **Red River** Formation currently accounts for 61%

of North Dakota's horizontal production. Additional development will probably occur only after unitization of the Cedar Hills-**Red River** 'B' Pool.

A total of 43 wells were drilled to the **Madison** Group throughout North Dakota, of which 40 wells were completed as producers for a success ratio of 93%. The **Madison** Group currently accounts for 30% of North Dakota's horizontal production. Operators on the eastern flank of the Williston Basin drilled only three wells in the **Madison** Group, all of which were producers. Production is shallow, coming from a depth of approximately 4,000 feet (1,220 meters). The average **Madison** Group horizontal well in this area takes 14 days from spud to total depth, has a lateral section of 1,960 feet (600 meters), with an initial average production rate of 170 bopd (27 cmopd). Twenty-eight wells were drilled in the **Madison** Group throughout North Dakota in Billings, Burke, Dunn, McKenzie, Mountrail and Williams Counties. The average well in this area takes 35 days from spud to total depth, has a lateral section of 2,510 feet (865 meters), with an initial average production rate of 120 bopd (19 cmopd). Tri-lateral **Madison** Group wells in Burke County have shown great promise and the average tri-lateral well takes 34 days from spud to total depth, has a lateral open hole section of over 13,000 feet (4,020 meters), with an initial average production rate of 238 bopd (38 cmopd).

The **Bakken** Formation accounts for 45% of the cumulative horizontal production, although it only accounts for 8% of present horizontal production. The **Bakken** Formation did not see any horizontal activity in 1998. Production from the 137 wells in December averaged 12 bopd (2 cmopd). The wells are still economic since the average water cut is only 7%, a premium oil price is paid for the sweet crude, and the current production decline is minimal.

The five most active counties in 1998 (vertical + horizontal) were Bowman, Burke, Williams, Billings and McKenzie Counties. Bowman County had 29 wells completed as producers, almost all of which were from horizontal wells drilled in the **Red River** 'B' Pool. Production dropped 8% during 1998, slipping Bowman to our number two producing county for the year. Burke County had 11 wells completed as producers, all of which were horizontal wells drilled in the **Madison** Group. Production increased 41% during 1998 and it appears additional development will occur in 1999. Williams County had 9 wells completed as producers, two of which were from horizontal wells drilled in the **Madison** Group and production was flat throughout the year. Although Stark County only had a slight production increase during the year and only 2 wells completed as producers, it ended the year as our number one producing county, due almost

entirely to the EOR projects in the **Lodgepole** Formation.

Activity in 1999 has started very slow for North Dakota. Depressed oil prices have significantly affected horizontal plays in the State, nevertheless, several **Madison** plays continue to have interest, a portion of the **Red River** 'B' Pool may be unitized before the end of the year, and some operators are exploring the possibility of coal bed methane in the State.

North Dakota oil production is assessed a **gross production tax** and an **oil extraction tax**. All existing wells and new wells drilled are assessed the 5% gross production tax. The oil extraction tax is 4% for all wells drilled after April 27, 1987 and 6.5% for all wells drilled prior to April 27, 1987. The North Dakota Legislature has passed numerous exemptions to the oil extraction tax. The following waivers on the oil extraction tax can be obtained:

---All production from a stripper well property.
---10 years following production from a two-year inactive well.
---10 years following the date incremental production commences from a tertiary recovery project.
---5 years following the date incremental production commences from a secondary recovery project.
---The first 24 months of production for all new horizontal wells.
---The first 15 months of production for new vertical wells.
---The 12 months following a qualifying workover project.
---9 months following production from a horizontal reentry well.
---The first 60 months of production for all wells located within the boundary of an Indian Reservation.

North Dakota has passed several incentives due to the depressed oil price. A few of them include:

---Elimination of the $100 application fee for stripper wells.
---Elimination of the $100 application fee for workover projects.
---Waiver from one-year abandonment of wells.
---Oil price assistance loan program.

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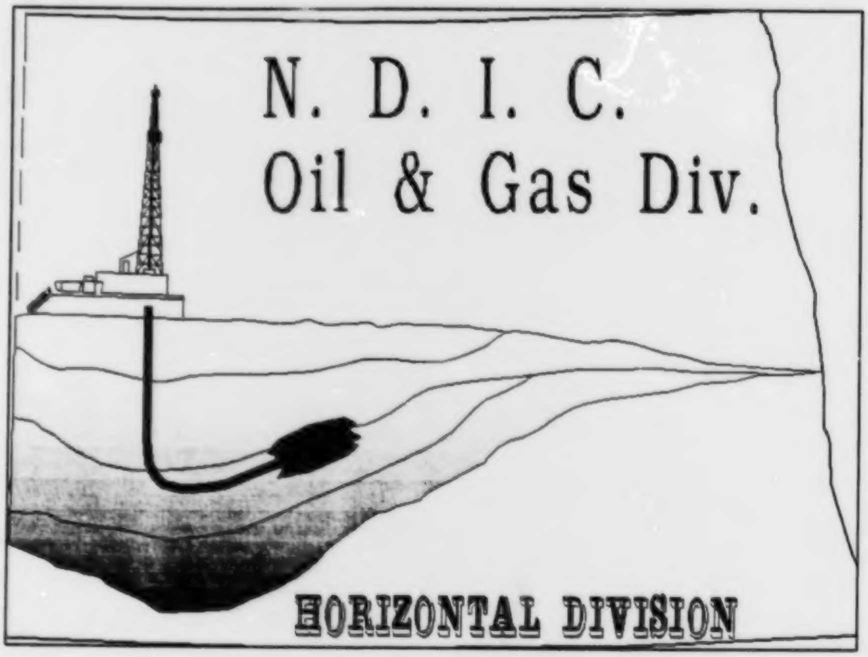
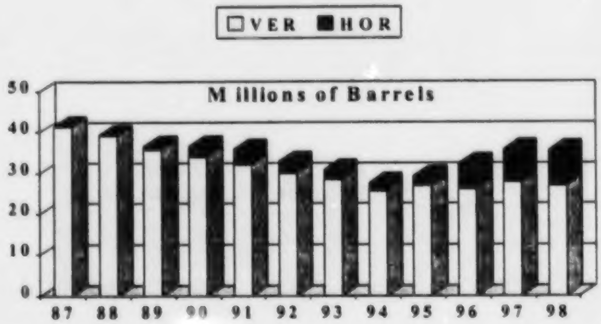


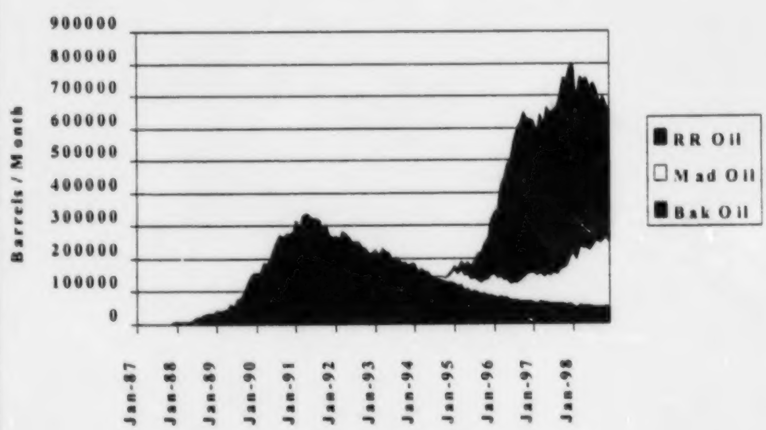
NORTH DAKOTA HORIZONTAL UPDATE

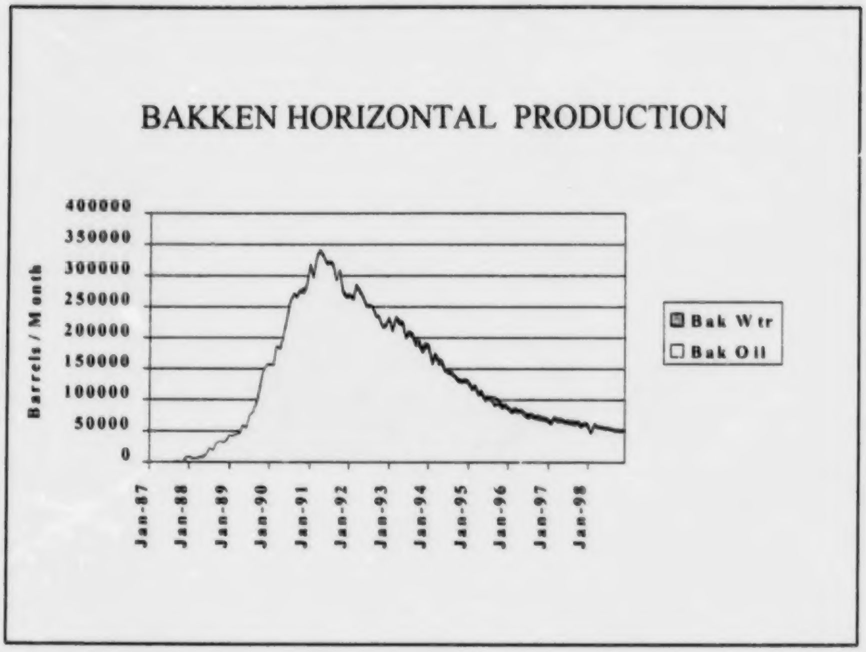
Bruce E. Hicks
Manager of Horizontal Drilling

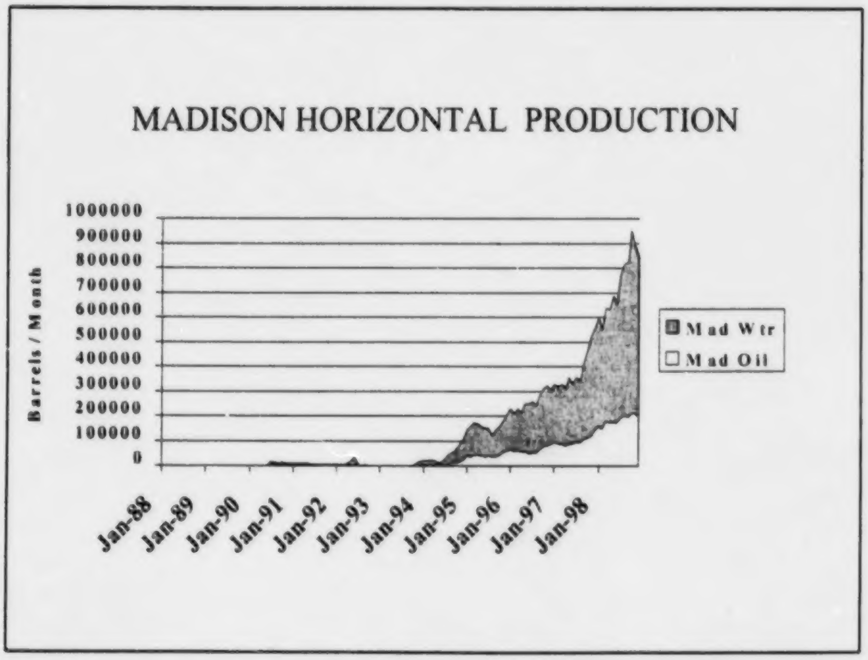
NORTH DAKOTA
YEARLY OIL PRODUCTION

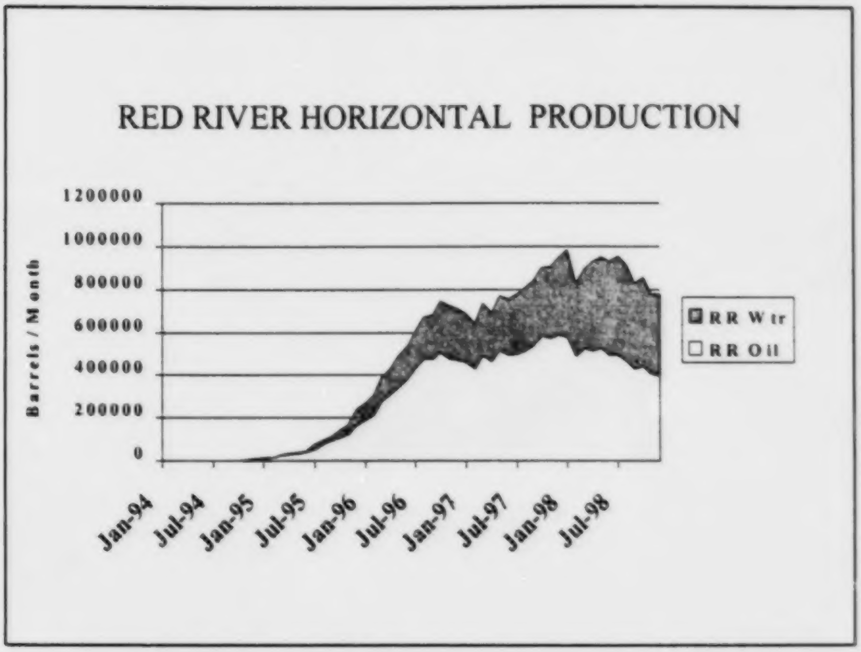


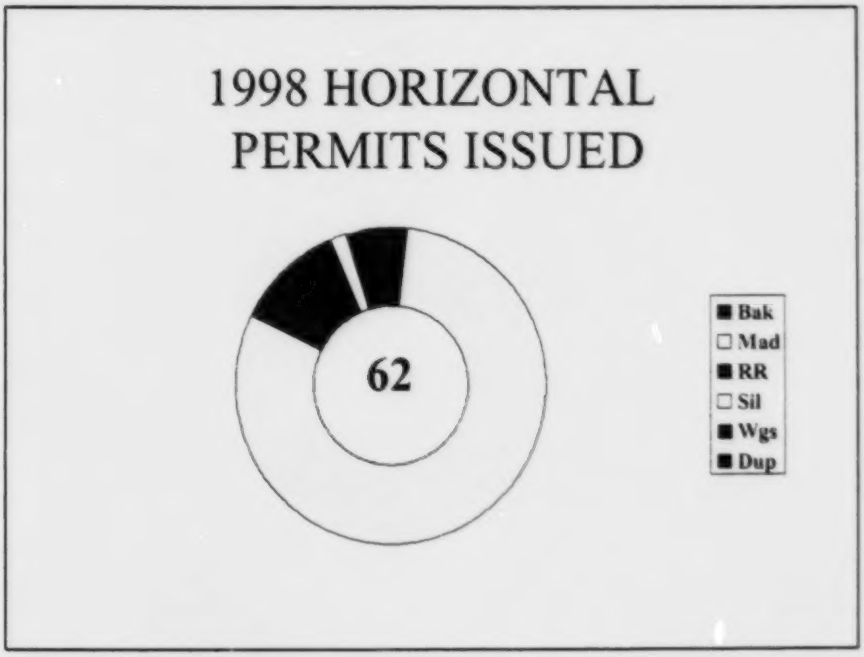
HORIZONTAL OIL PRODUCTION



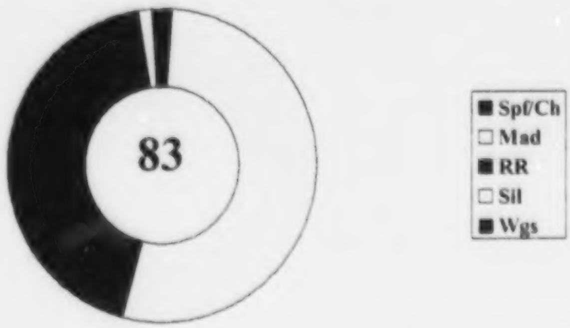

BAKKEN HORIZONTAL PRODUCTION
Barrels / Month
400000
350000
300000
250000
200000
150000
100000
50000
0
Jan-87
Jan-88
Jan-89
Jan-90
Jan-91
Jan-92
Jan-93
Jan-94
Jan-95
Jan-96
Jan-97
Jan-98
Bak Wtr
Bak Oil


MADISON HORIZONTAL PRODUCTION
Barrels / Month
1000000
900000
800000
700000
600000
500000
400000
300000
200000
100000
0
Jan-88
Jan-89
Jan-90
Jan-91
Jan-92
Jan-93
Jan-94
Jan-95
Jan-96
Jan-97
Jan-98
Mad Wtr
Mad Oil

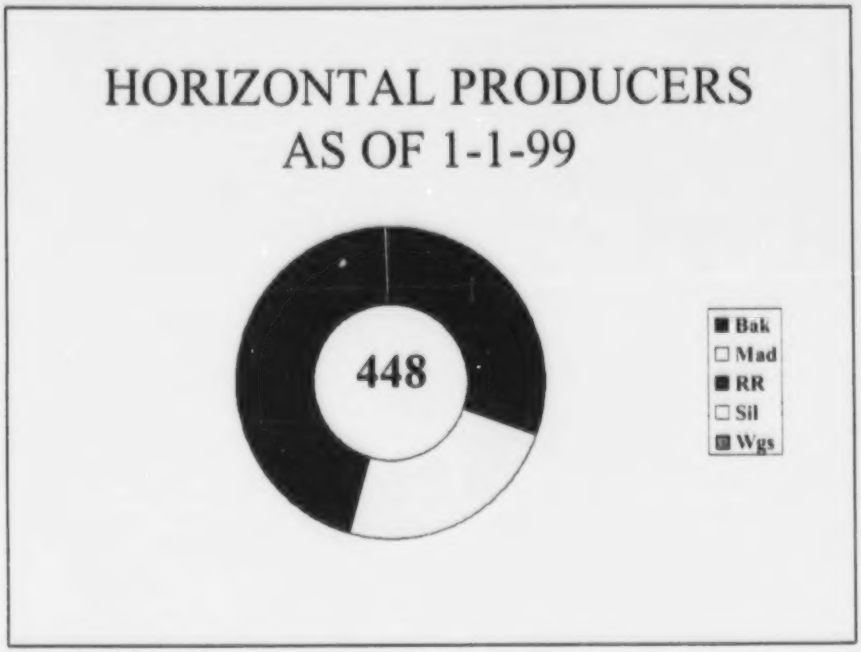

RED RIVER HORIZONTAL PRODUCTION
1200000
1000000
800000
600000
400000
200000
0
Barrels / Month
RR Wtr
RR Oil
Jan-94
Jul-94
Jan-95
Jul-95
Jan-96
Jul-96
Jan-97
Jul-97
Jan-98
Jul-98

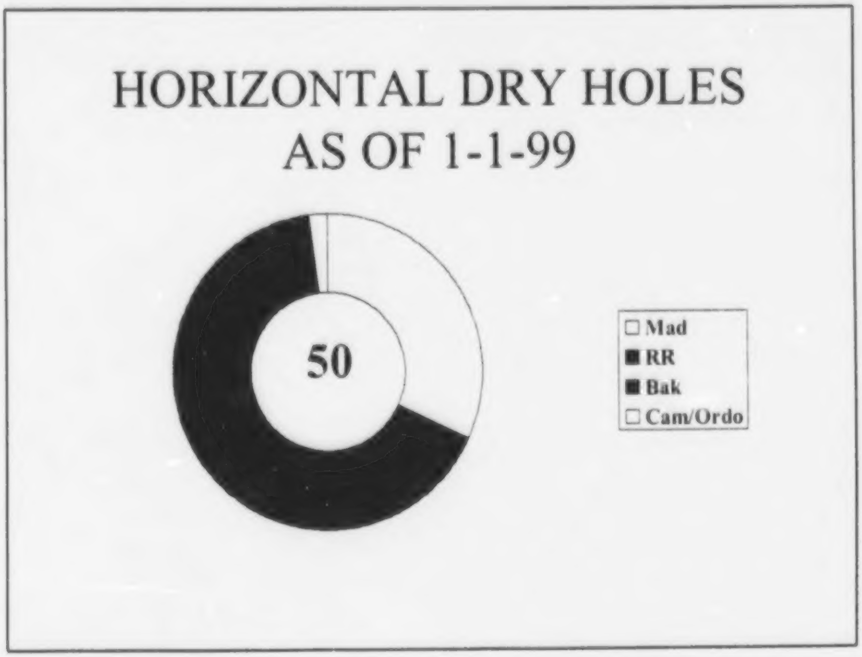

1998 HORIZONTAL
PERMITS ISSUED
62
Bak
Mad
RR
Sil
Wgs
Dup

1998 HORIZONTAL DRILLED

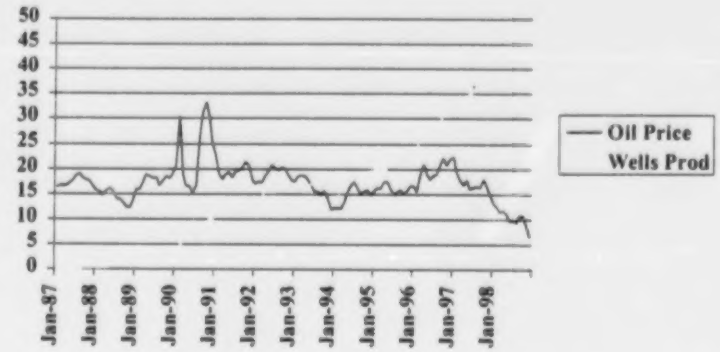


1998 HORIZONTAL PRODUCERS

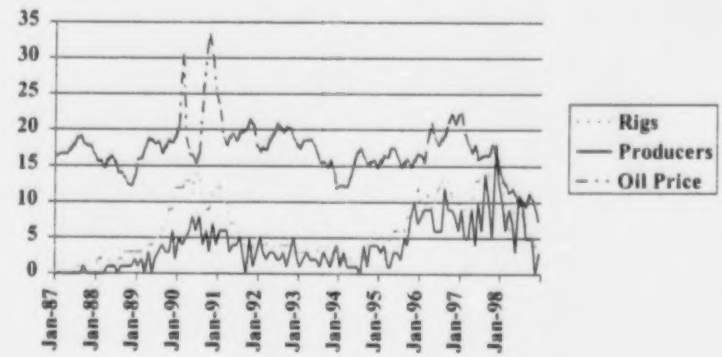

HORIZONTAL PRODUCERS
AS OF 1-1-99
448
Bak
Mad
RR
Sil
Wgs


HORIZONTAL DRY HOLES
AS OF 1-1-99
50
Mad
RR
Bak
Cam/Ordo

HORIZONTAL WELL STATISTICS



HORIZONTAL WELL STATISTICS



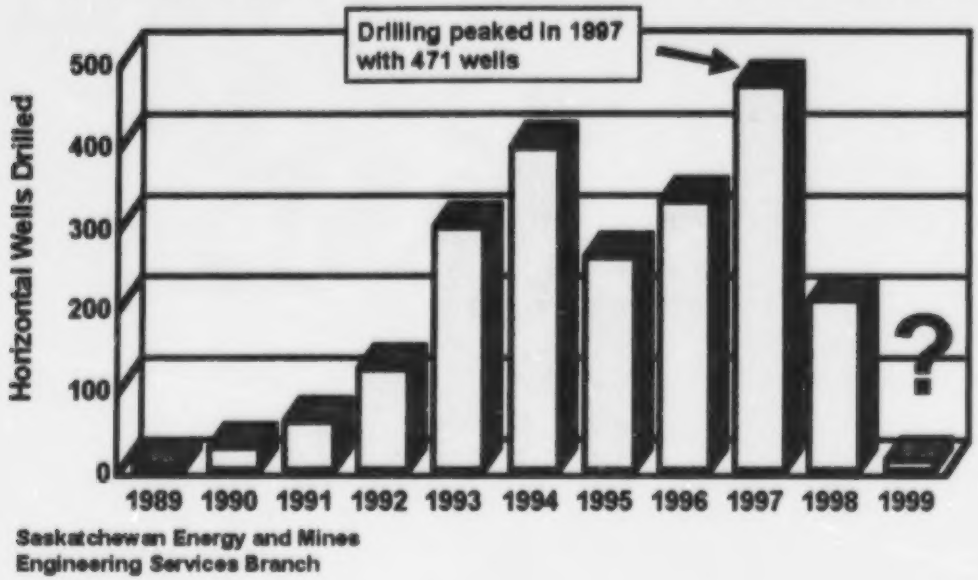
NORTH DAKOTA INCENTIVES

- Relief from one year abandonment of wells
- Eliminate $100 fee on stripper applications
- Eliminate $100 fee on workover applications
- Oil price assistance loan program

SASKATCHEWAN WILLISTON BASIN HORIZONTAL WELL UPDATE

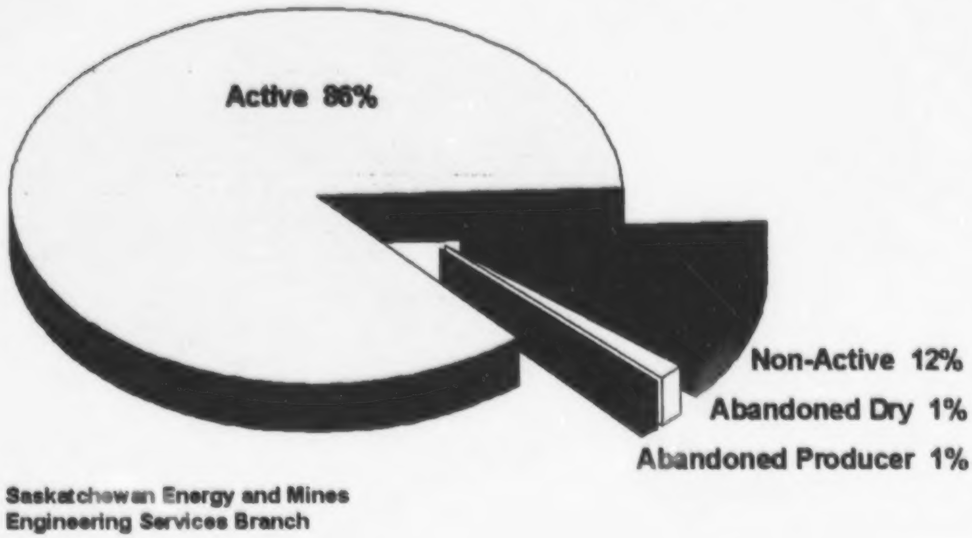
Chris Wimmer, P.Eng.
Saskatchewan
Energy and Mines

Horizontal Wells Drilled - Southeast Saskatchewan



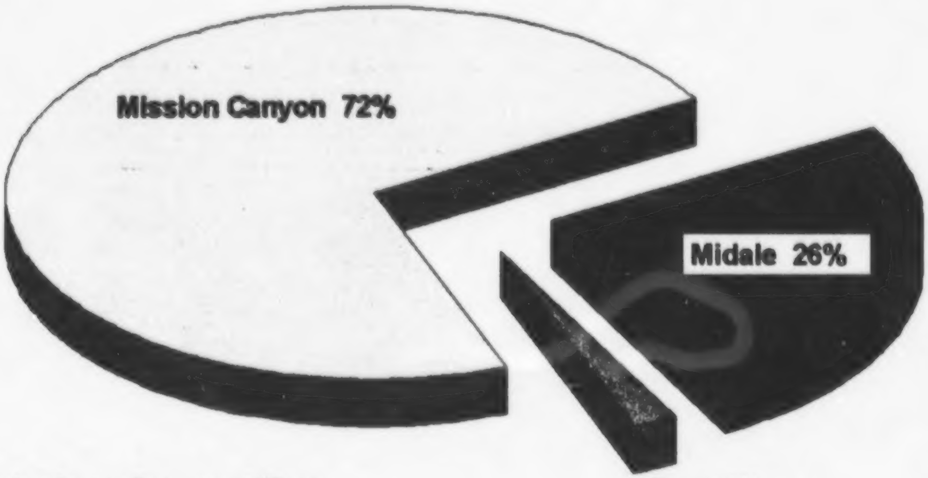
- The first horizontal well drilled in southeast Saskatchewan was in August, 1989
- Horizontal drilling increased rapidly with a peak of 471 wells drilled in 1997
- To the end of 1998, 2171 horizontal wells had been drilled
- Wells with multiple lateral sections are counted as a single well
- There are over 750 wells with multiple lateral sections (almost 1800 laterals in total)
- Drilling has slowed in recent months largely due to low oil prices

Horizontal Well Status December, 1998
Southeast Saskatchewan



- 1862 of the horizontal wells drilled are currently classified as active
- 252 are currently non-active
- 31 wells have been dry and abandoned
- Only 26 producing wells have been abandoned or recompleted as vertical wells

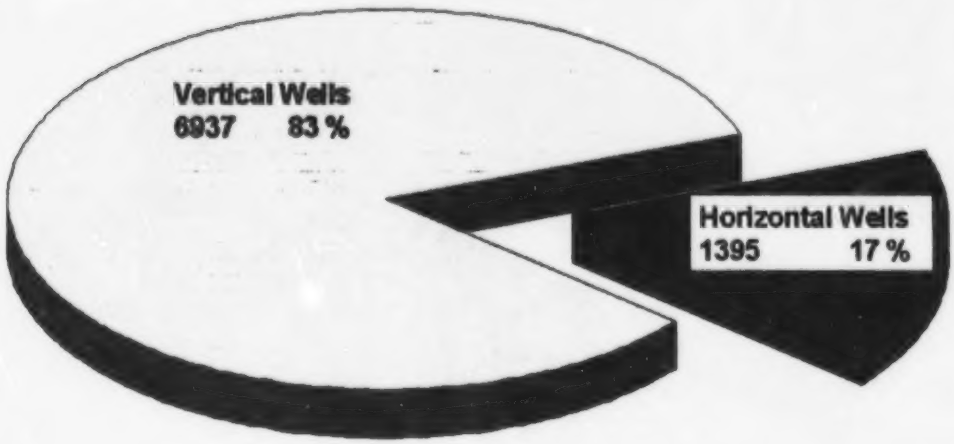
Horizontal Well Productive Zone December, 1998
Southeast Saskatchewan



Saskatchewan Energy and Mines
Engineering Services Branch

- Most of the horizontal wells in SE Saskatchewan have been drilled in the Mississippian carbonates
- 1488 wells have been drilled in the Mission Canyon group, primarily in the Frobisher-Alida Beds
- 526 wells have been drilled in the Midale Beds, 234 within the Weyburn Midale Beds Pool
- 37 wells have been drilled in zones deeper than the base of the Mississippian, 25 in the Ordovician Red River Formation

Producing Oil Wells December, 1998
Southeast Saskatchewan



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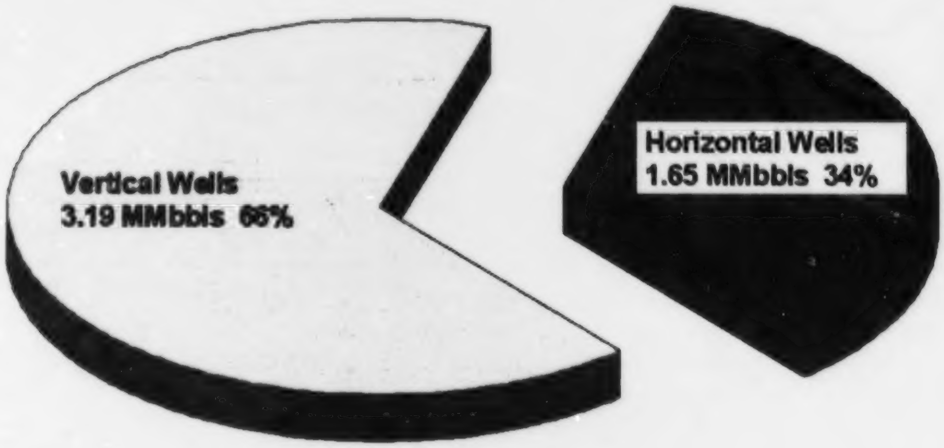
Engineering Services Branch

- By the end of 1998 17 % of all producing wells in SE Saskatchewan were horizontal

Monthly Oil Production December, 1998
Southeast Saskatchewan



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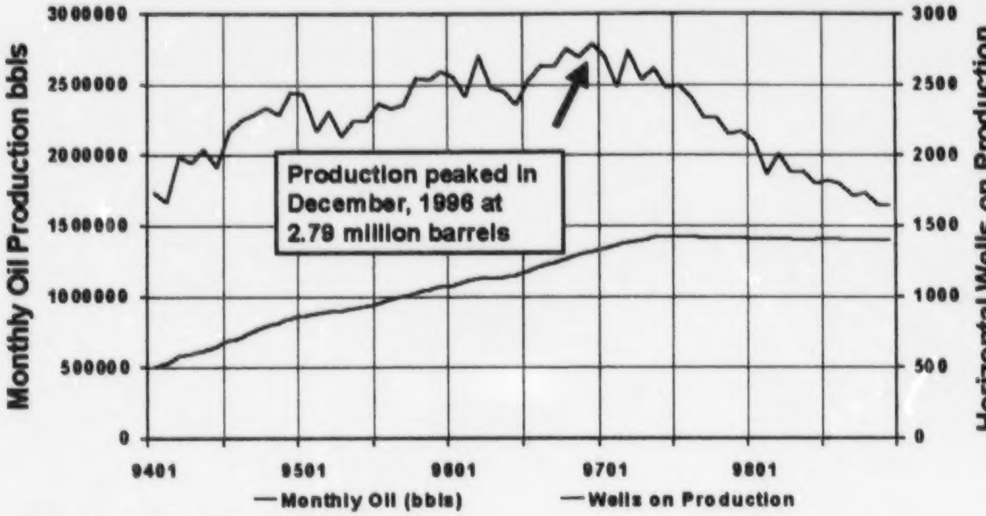
Engineering Services Branch

- Horizontal wells account for 17 % of the producing wells in SE Saskatchewan, however, 34 % of the monthly production volume is from horizontal wells

Horizontal Well Production - Southeast Saskatchewan



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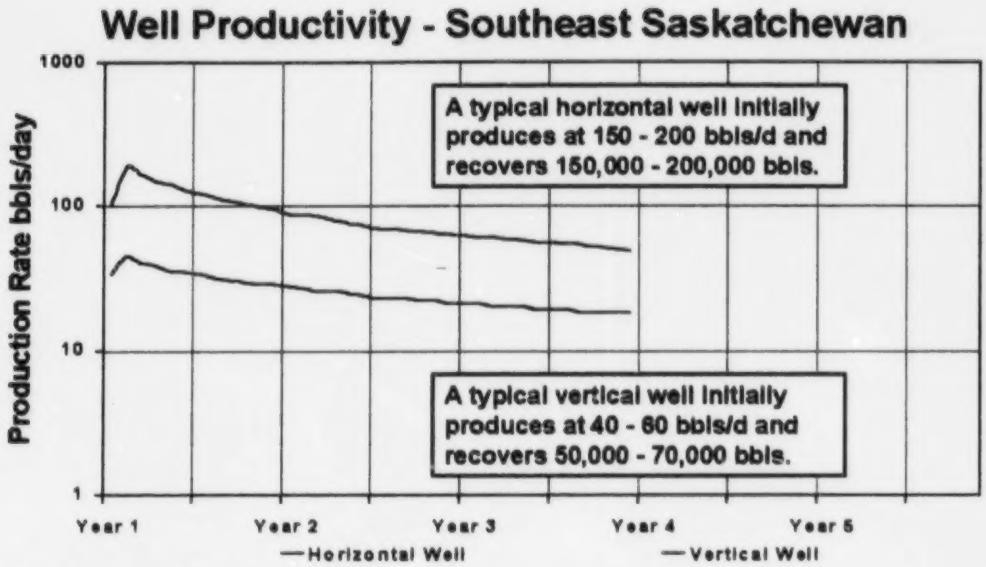
Engineering Services Branch

- Monthly oil production from horizontal wells reached a peak of 2.79 million barrels in December, 1996
- The number of producing horizontal wells reached a peak of approximately 1400 in mid 1997
- In December, 1998, 1395 horizontal wells reported production of 1.65 million bbls



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Engineering Services Branch

- A sample of over 1000 horizontal wells and over 1000 vertical wells drilled between August, 1989 and September, 1995 was used to determine a typical production profile for each type of well

- Decline analysis was applied to the well profiles to estimate the ultimate recovery

- The ultimate recovery of a typical horizontal well within the Williston Basin is estimated to be 2 to 3 times that of a typical vertical well

BACK FROM THE BRINK

By

Lynn D. Helms

and

Bruce E. Hicks

BACK FROM THE BRINK

By Lynn D. Helms & Bruce E. Hicks

Horizontal Infill Drilling Revives Marginal Vertical Well Producing Pools

ABSTRACT

Oil & gas operators in the State of North Dakota have utilized horizontal drilling technology to infill drill 23 pools previously developed with vertical wells. Current daily production from those horizontal wells totals 4,186 BOPD. Current cumulative production form those horizontal wells is 4,060 MBO.

This study examines a number of projects in non-unitized, unitized, and unitized-EOR projects to determine the following:

1) How much of the current and cumulative horizontal well production is incremental?

2) What is the Estimated Ultimate Incremental Recovery (EUIR) of each project?

3) What effect has there been on vertical well production from nearby horizontal wells?

The study also suggests some reasons for the vertical - horizontal well responses observed.

NON-UNITIZED PROJECTS

Oil & gas operators in the State of North Dakota have utilized horizontal drilling technology to infill drill 12 non-unitized pools previously developed with vertical wells. Current daily production from these non-unitized horizontal projects totals 2,436 BOPD, and current cumulative production is 2,929 MBO.

Following is a detailed discussion of 2 nonunitized pools with significant horizontal infill drilling.

TR Madison Pool

TR Madison Pool produces from a structural-stratigraphic trap in the upper Mission Canyon formation. The pool is located on the Billings Nose in the western portion of the Williston Basin in Billings County, North Dakota.

The first graph shows historical oil, water, and gas production from 1979 to present.

TR Pool was discovered in 1978 and developed on 160-acre spacing with 38 vertical wells. The pool was infill drilled with one horizontal well in 1993 in the southern most end of the pool.

The pool map shows locations of horizontal and vertical wells with cumulative oil posted next to surface location of each well. Note the nearest vertical well has produced 416,891 BO and the horizontal well has already produced 167,608 BO. The horizontal well is currently declining at an approximately 12% annual rate and may produce 500,000 BO before reaching its economic limit.

Slide TR-1 shows the location and oil production for the Mosser #2-26 and Mosser #30-26H wells. The horizontal well is 589 feet from the vertical well at the closest point. Note the lack of any discernible effect on the vertical well production from the horizontal well. We can conclude from this data that 100% of the oil produced from the horizontal well is in fact incremental recovery.

<u>Wayne Madison Pool</u>

Wayne Madison Pool produces from a structural trap in the upper Mission Canyon formation "Wayne Pay". The pool is located on the northeast flank of the Williston Basin in Bottineau County, North Dakota.

Wayne Pool was discovered in 1957 and developed on 80-acre spacing with 7 vertical wells by 1963, but all were PNA by 1968 with cumulative production of only 180 MBO / 1,900 MBW. The pool was redeveloped on 40-acre spacing with 33 vertical wells beginning in 1977 and infill drilled with 14 horizontal wells from 1994 through 1998. The horizontal wells were infilled drilled between virtually every vertical producer in the pool.

The first graph shows historical oil and water production from 1979 to present. Note the strong water drive reservoir. Oil production was increased four-fold due to the horizontal drilling project.

The pool map shows locations of horizontal and vertical wells with cumulative oil posted next to surface location of each well. The current cumulative oil of the horizontal wells already exceeds the vertical wells cumulative oil in many portions of the pool.

Slide Wayne-1 shows the location and oil production for the Oscar Fossum #1 and Oscar Fossum #H4 wells. The horizontal well is 176 feet from the vertical well at the closest point. Note the lack of any discernible effect on the vertical well production from the horizontal well. We can conclude from this data that 100% of the oil produced from the horizontal well is in fact incremental recovery.

Slide Wayne-2 shows the location and oil production for the Bronderslev #2 and Bronderslev #4H wells. The horizontal well is 180 feet from the vertical well at the closest point. Note the lack of any discernible effect on the vertical well production from the horizontal well. We can conclude from this data that 100% of the oil produced from the horizontal well is in fact incremental recovery.

Slide Wayne-3 shows the location and oil production for the William Steinhaus #2 and Ballantyne-State/Steinhaus #H1 wells. The horizontal well is 53 feet from the vertical well at the closest point. Note the lack of any discernible effect on the vertical well production from the horizontal well. We can conclude from this data that 100% of the oil produced from the horizontal well is in fact incremental recovery.

The performance curve from the vertical wells appears to drop off significantly from the expected decline, but upon further evaluation, it becomes apparent the oil decline is due to the abandonment of 8 high water producers in the pool.

Horizontal oil production is currently declining at an approximate 23% annual rate. A pilot EOR project was initiated in 1998 and future implementation of pool-wide pressure support will be evaluated.

The horizontal infill project was extremely successful and over 2 million barrels of incremental oil will be produced for an average recovery of 164,000 BO per horizontal well.

UNITIZED PROJECTS

Oil & gas operators in the State of North Dakota have utilized horizontal drilling technology to infill drill 12 unitized pools previously developed with vertical wells. Current daily production from these nonunitized horizontal projects totals 1,750 BOPD, and current cumulative production is 1,131 MBO.

Following is a detailed discussion of 3 unitized pools with significant horizontal infill drilling.

Cedar Creek Ordovician Unit

The Cedar Creek Ordovician Pool produces from a structural trap in the upper Red River formation. The pool is located on the Cedar Creek Anticline on the southwest edge of the Williston Basin in Bowman County, North Dakota.

The Cedar Creek Pool was discovered in 1960 and developed on 80-acre spacing with 40 vertical wells. The pool has been infill drilled with 4 horizontal wells from 1995 to present.

The first graph shows historical oil, water, and gas production along with water injection from 1980 to present.

The pool map shows locations of horizontal and vertical wells with cumulative oil posted next to surface location of each well.

Slide CCOU-1 shows the location and oil production for the Cedar Creek Unit B8 #43-12A-37 and Cedar Creek #33X-12AH68 wells. The horizontal wells a is 1485 feet from the vertical well at the closest point. Note the lack of any discernible effect on the vertical well production from the horizontal well. We can conclude from this data that 100% of the oil produced from the horizontal well is in fact incremental recovery.

Three of the 4 horizontal wells drilled in CCOU were economic failures. All 3 failures were drilled on the eastern edge of the unit in an attempt to extend the productive limits of the reservoir. Note on the edge of the map the west edge of the Cedar Hills Pool where horizontal drilling has been used to develop a resource completely uneconomic with vertical wells. This result indicates that tackling too much geological risk in combination with other variables can be fatal to your project.

The horizontal well drilled in the southern most part of the Cedar Creek Ordovician Unit appears to have an ultimate recovery over 200,000 BO. It appears this horizontal well has penetrated reservoir containing oil "banked" from the EOR project.

The horizontal infill project had limited success, but indicates additional potential with over 380,000 barrels of incremental oil to be produced for an average recovery of 95,000 BO per horizontal well.

Haas Madison Pool

The Haas Madison Pool produces from a stratigraphic trap in the upper Mission Canyon formation. The pool is located on the on the northeastern flank of the Williston Basin in Bottineau County, North Dakota.

The Haas Pool was discovered in 1957 and developed on 80-acre spacing with 18 vertical wells. The pool has been infill drilled with 14 horizontal wells from 1994 to present. In 1995 a problem with pressure depletion was recognized and the pool was unitized with water injection commencing in September, 1996.

The first graph shows historical oil, water, and gas production along with water injection from 1981 to present. Note production for 1998 has stabilized and it appears water injection is presently enhancing recovery from the unit. The next two graphs show the same historical data, one representing only the vertical wells and the other representing only the horizontal wells.

Slide HMU-1 shows the oil production performance curve for the vertical wells and also the oil production performance curve of the horizontal wells. Notice how 18 months after injection begins the production decline of both vertical and horizontal wells has halted. Note the lack of any discernible effect on the vertical wells production from the horizontal wells. We can conclude from this data that 100% of the oil produced from the horizontal wells is in fact incremental recovery and horizontal infill drilling can be successfully combined with enhanced oil recovery in a depleted reservoir to recover large amounts of incremental oil.

Tioga Madison Unit

Tioga Madison Pool produces from a structural trap in the upper Mission Canyon formation. The pool is located on the Nesson Anticline in the central portion of the Williston Basin in Burke, Mountrail and Williams Counties, North Dakota.

The first graph shows historical oil, water, and gas production, along with water injection from 1982 to present.

Tioga Pool was discovered in 1952 and developed on 80-acre spacing with 255 vertical wells. The pool has been infill drilled with 8 horizontal wells from 1996 to date, but less than half of the unitized area has been tested.

The first 3 horizontal wells drilled in Tioga Madison Pool were economic failures. All 3 followed the "Canadian" model of drilling parallel to a known fracture trend and 1 well tested deeper geologically risky pay. The 4th well was a tremendous success and led to 7 consecutive additional successes (including several horizontal re-entries to add a properly orientated horizontal leg). This illustrates the need to approach horizontal development drilling as a multiwell program with a steep learning curve. Several attempts may be required before the correct combination of geology, orientation, zone, and drilling practices is discovered. In addition we can conclude that tackling too much geological risk in combination with other variables can be fatal to your project.

The pool map shows locations of horizontal and vertical wells with cumulative oil posted next to surface location of each well. The vertical wells have been extremely profitable and have cums ranging between 150,000 BO and 2 million BO.

Slide TMU-1 shows the location and oil production for the TMU #H-140 and TMU #G-141-H wells. The horizontal well is 42 feet from the vertical well. The horizontal well was drilled from an existing vertical well producing approximately 8 bopd at the time the horizontal workover project was initiated. Approximately 15,000 BO of vertical well remaining reserves were lost due to the horizontal workover project. Note the lack of any discernible effect on the offset vertical well production from the horizontal well. We can conclude from this data that all

but 15,000 BO of the oil produced from the horizontal well is in fact incremental recovery.

Slide TMU-2 shows the location and oil production for the TMU #L-144 and TMU #K-143 wells. The horizontal well is 1880 feet from the vertical well at the closest point. Note the lack of any discernible effect on the vertical well production from the horizontal well. We can conclude from this data that 100% of the oil produced from the horizontal well is in fact incremental recovery.

The TMU #L-146XH was another horizontal workover project performed on an existing vertical well. The horizontal leg was drilled between 3 abandoned vertical producers. Production was approximately 20 bopd at the time the horizontal workover project was initiated. Approximately 100,000 BO of vertical well remaining reserves were lost due to the horizontal workover project, although the horizontal well should recover over 150,000 BO (50,000 BO incremental) . We can conclude from this data that all but 100,000 BO of the oil produced from the horizontal well is in fact incremental recovery.

CONCLUSION

Table 1 lists the results of **horizontal infill drilling in existing vertical well pools** in North Dakota. The numbers are amazing!

In conclusion, you don't have to discover a new producing province to make money in North Dakota with horizontal drilling (although we encourage you to try). Tremendous quantities of incremental oil lie discovered but unproducible between the vertical wells of North Dakota's old pools. Horizontal drilling truly can bring them **BACK FROM THE BRINK**.

INCREMENTAL OIL PRODUCED

NON-UNITIZED PROJECT	POOL	WELLS	DEC98 BOPD	DEC98 CUM	ROR	LOST VERT	EUIR
CARTER	MI/NE	1	549	15910	520000	0	535910
CEDAR HILLS	RR B	5	382	528922	563447	0	1092369
ELKHORN RANCH	BAK	1	0	97329	0	0	97329
ELMS	MAD	2	137	106213	448196	0	554409
HAAS	MAD	12	365	547202	718146	0	1265348
LAKE DARLING	MAD	1	40	69372	83091	0	152463
LONE TREE	MAD	2	29	60300	90413	0	150713
RENVILLE	MAD	1	35	28948	35426	0	64374
ROUGH RIDER	BAK	1	1	128914	0	0	128914
STINSON	MAD	1	37	22129	57904	0	80033
TR	MAD	1	127	165599	361872	0	527471
WAYNE	MAD	14	734	1157784	1135080	0	2292864
12 FIELDS		**42**	**2436**	**2928622**	**4013575**	**0**	**6942197**

UNITIZED PROJECT	POOL	WELLS	DEC98 CUM	DEC98 CUM	ROR	LOST VERT	EUIR
BEAVER LODGE	MAD	2	174	10769	245252	0	256021
BEAVER LODGE	SIL	1	17	17567	62135	40679	39023
CEDAR CREEK	ORDO	4	92	149078	231552	0	380630
CLEAR CREEK	MAD	1	136	35328	100574	0	135902
HAAS	MAD	2	92	85373	113310	0	198683
HORSE CREEK	RR	1	24	5878	81744	0	87622
L. MISSOURI	RR	1	39	68050	98108	72087	94071
M. POLE HILLS	RR	2	112	43534	113954	0	157488
N.ELKHORN.RANCH	MAD	2	253	104647	365685	0	470332
RIVAL	MAD	4	133	123402	248093	0	371495
TIOGA	MAD	8	582	401274	733880	129148	1006006
WABEK	MAD	2	96	86295	164136	5368	245063
12 UNITS		**30**	**1750**	**1131195**	**2558423**	**247282**	**3442336**
TOTAL		**72**	**4186**	**4059817**	**6571998**	**247282**	**10384533**

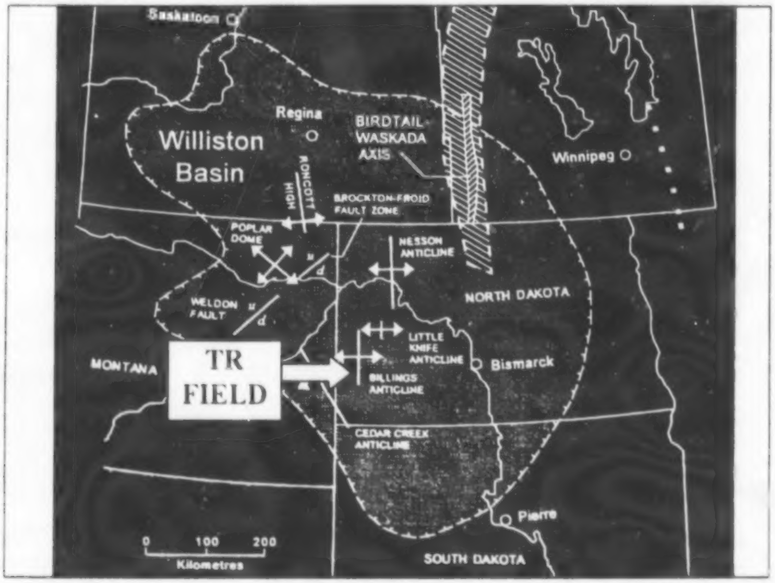
TABLE 1

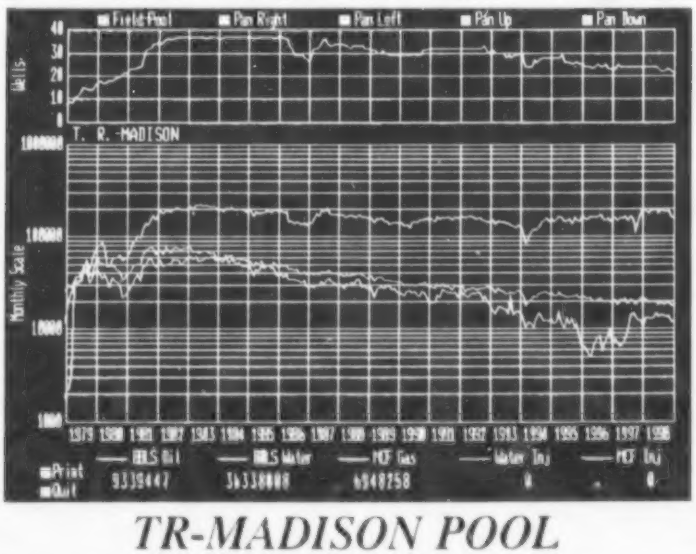
Carter-Midale/Nesson Pool
Cedar Hills-Red River 'B' Pool
Elkhorn Ranch-Bakken Pool
Elms-Madison Pool
Haas-Madison Pool
Lake Darling-Madison Pool
Lone Tree-Madison Pool
Renville-Madison Pool
Rough Rider-Bakken Pool
Stinson-Madison Pool
TR-Madison Pool
Wayne-Madison Pool

HORIZONTAL INFILL WELLS

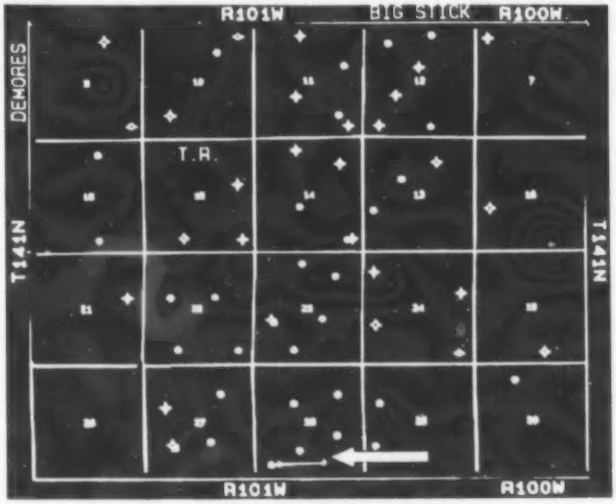
HORIZONTAL INFILL WELLS

TR-Madison Pool
Wayne-Madison Pool

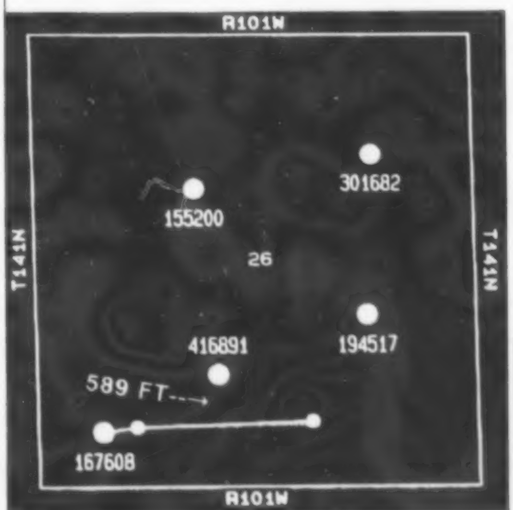




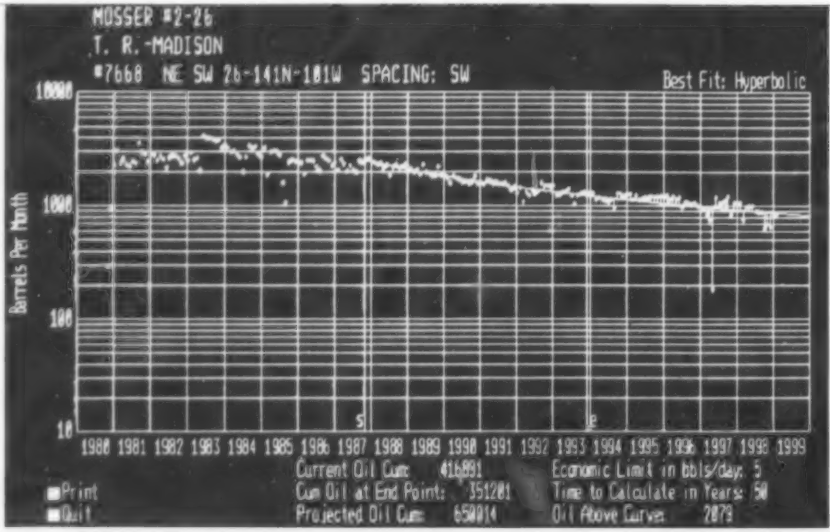
TR-MADISON POOL



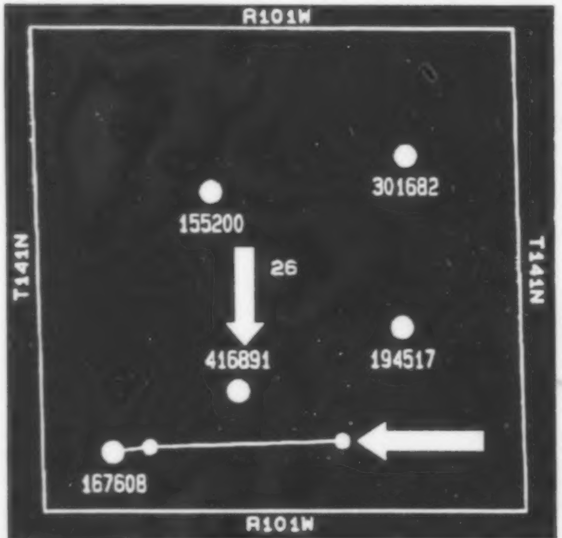
TR FIELD

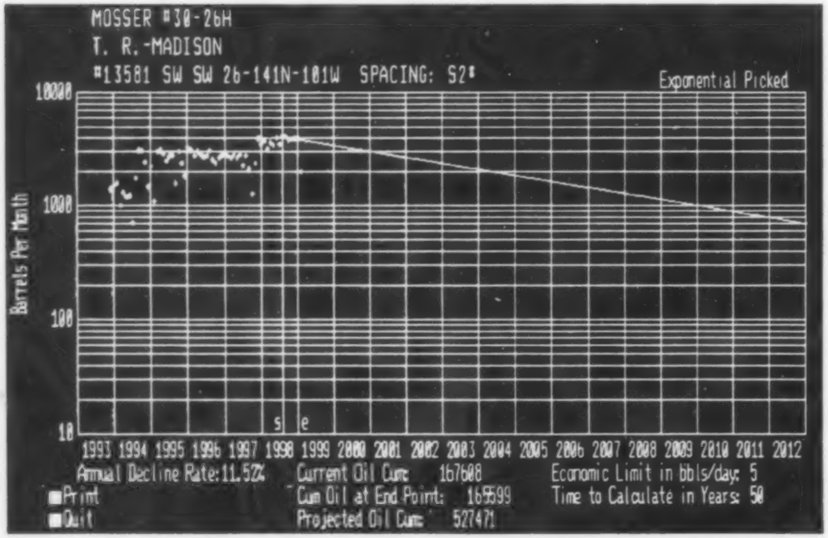


TR MADISON POOL



TR MADISON POOL

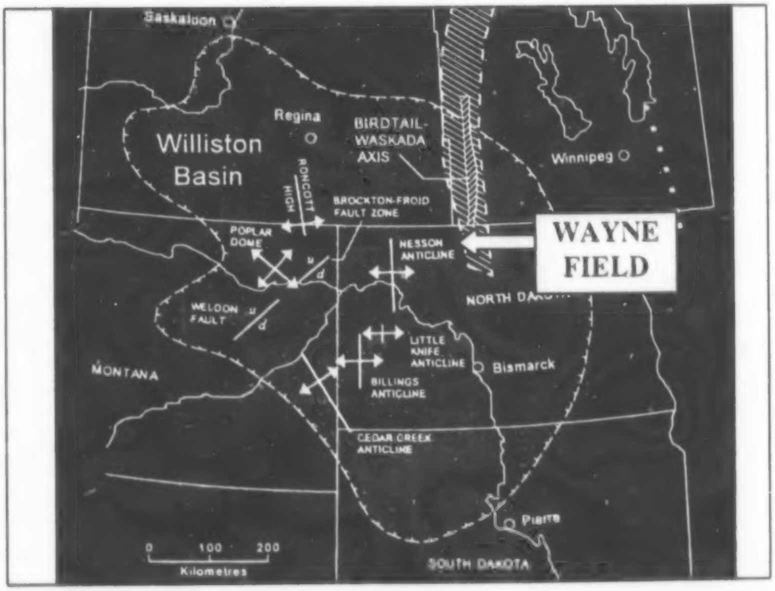


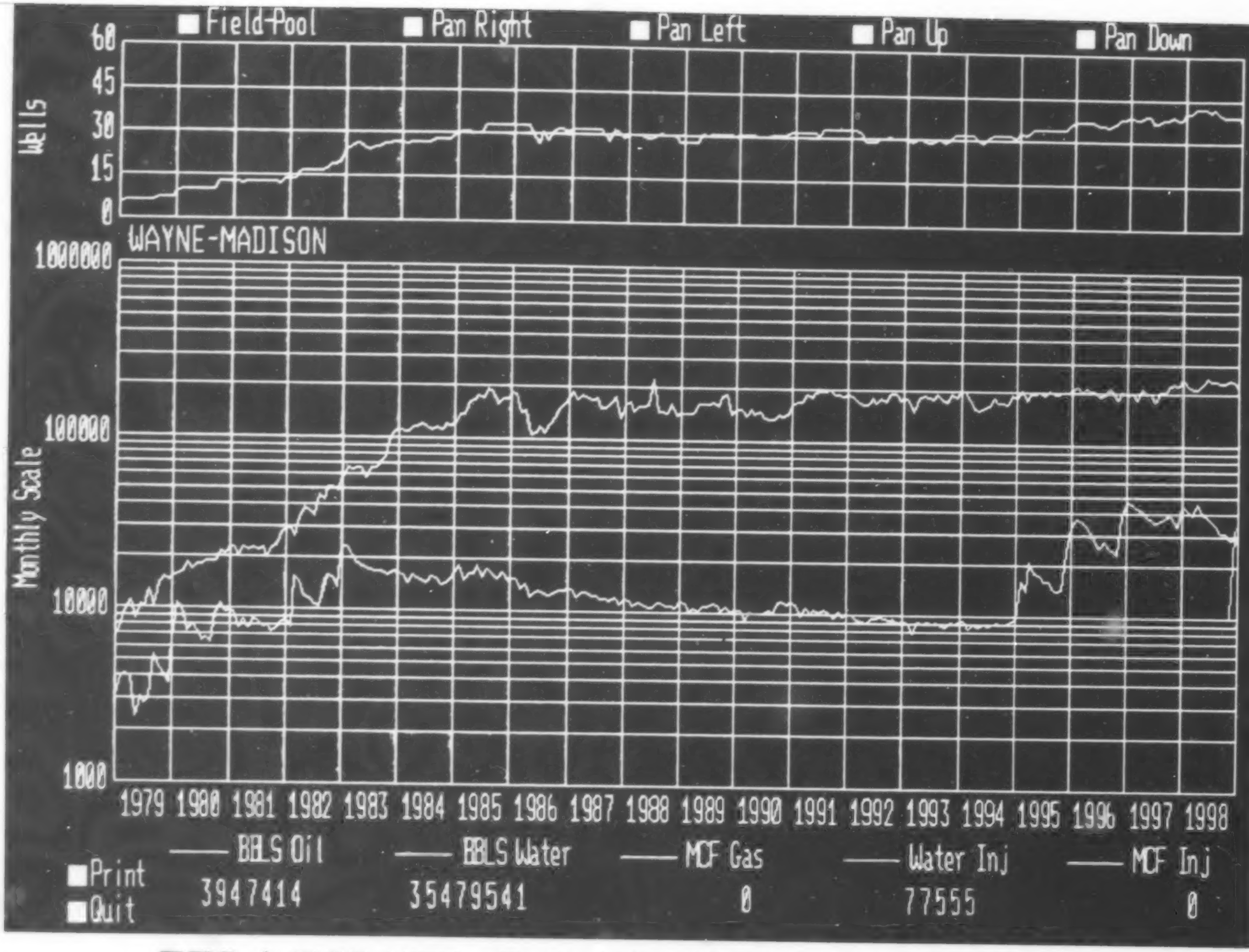


TR-1

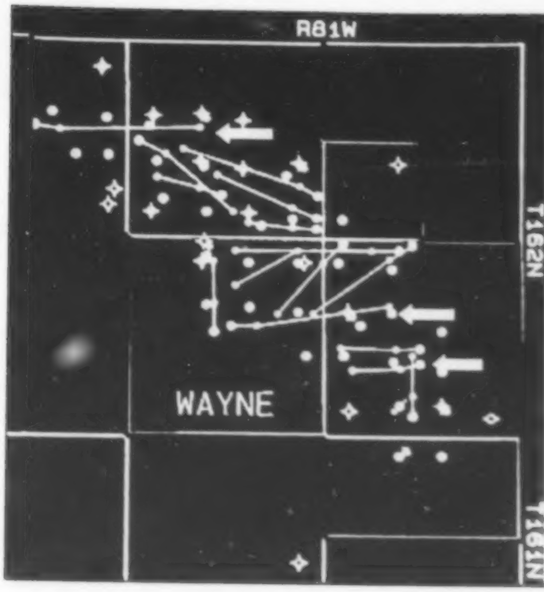
TR-MADISON POOL

- ONE HORIZONTAL WELL
- CUM = 165,599 BO (1-1-99)
- ROR = 362,000 BO
- INCREMENTAL = 527,000 BO

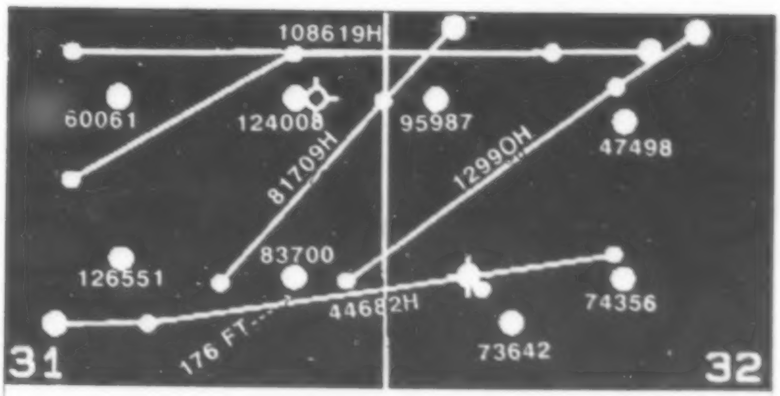




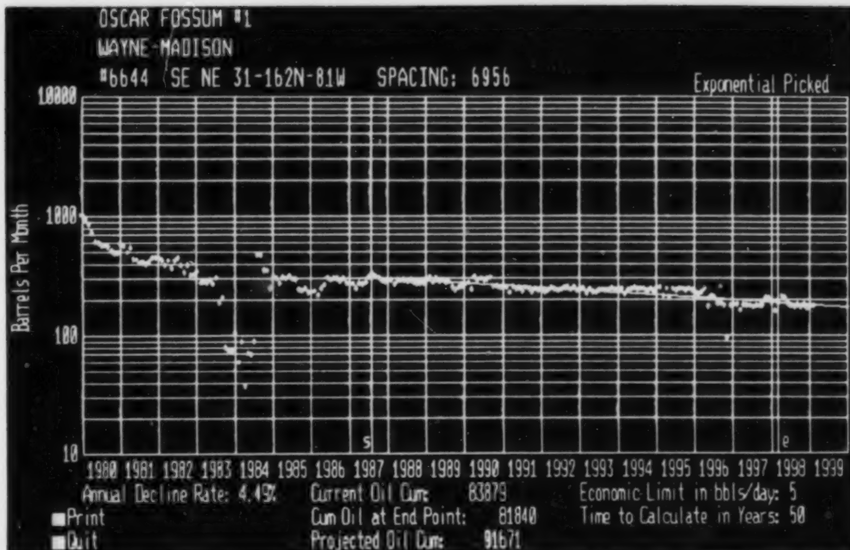
WAYNE-MADISON POOL

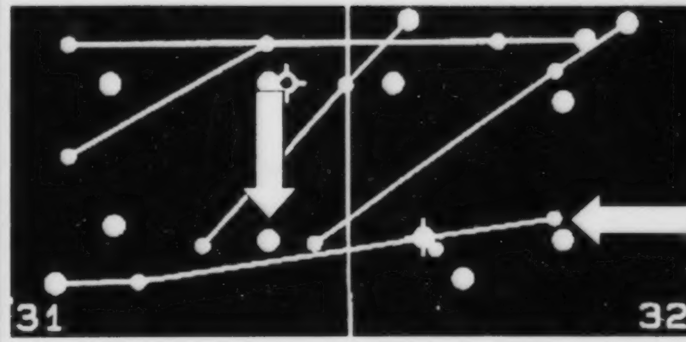


WAYNE FIELD

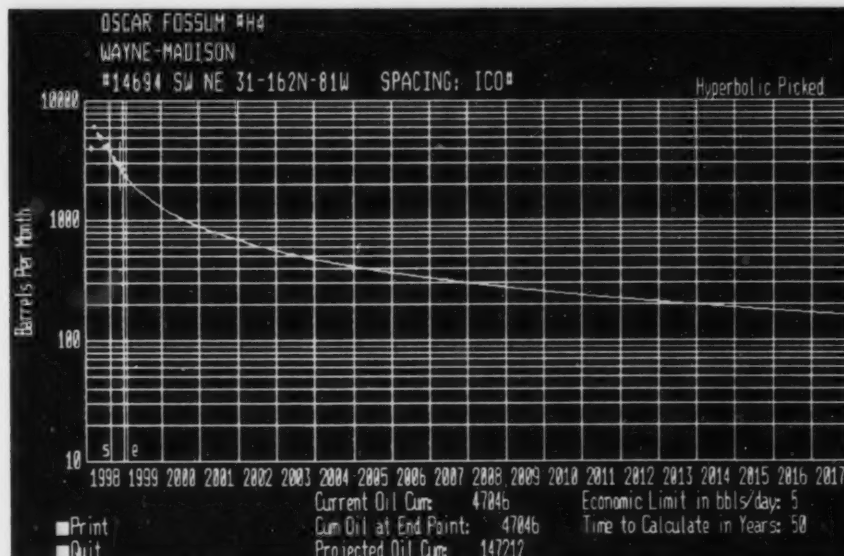


WAYNE-MADISON POOL

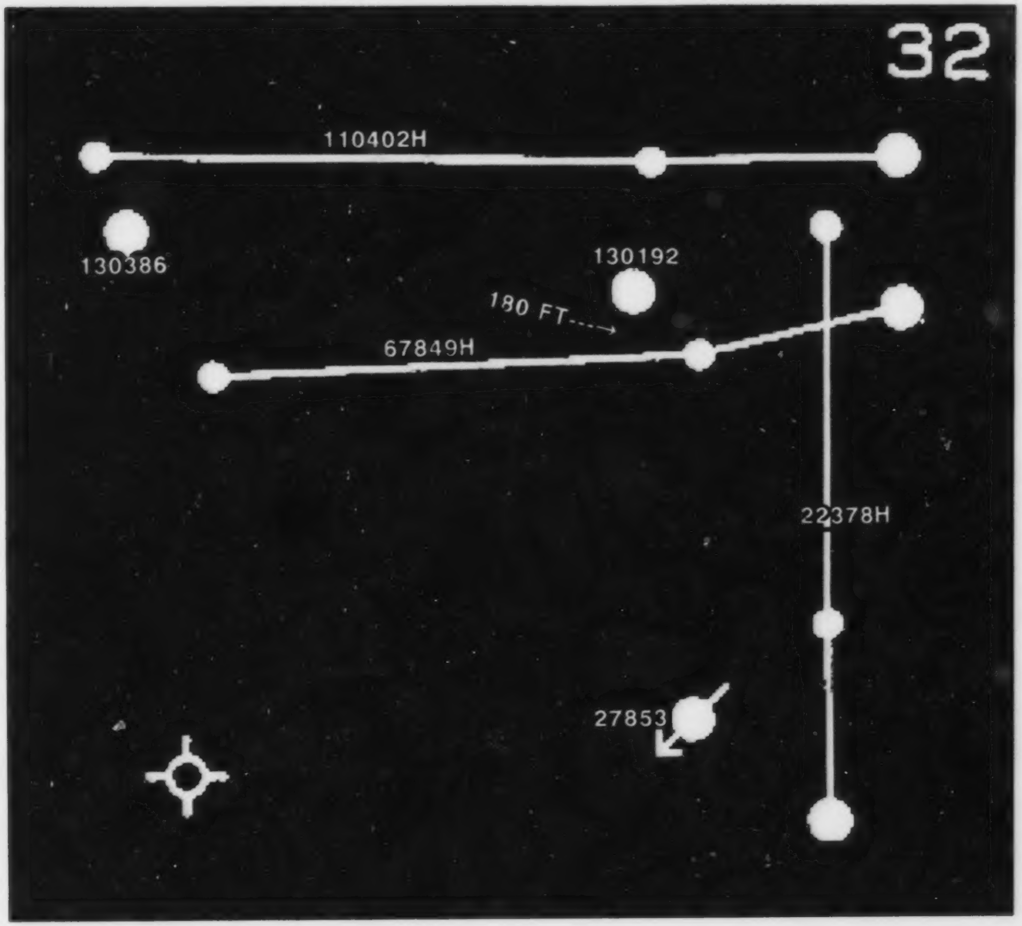




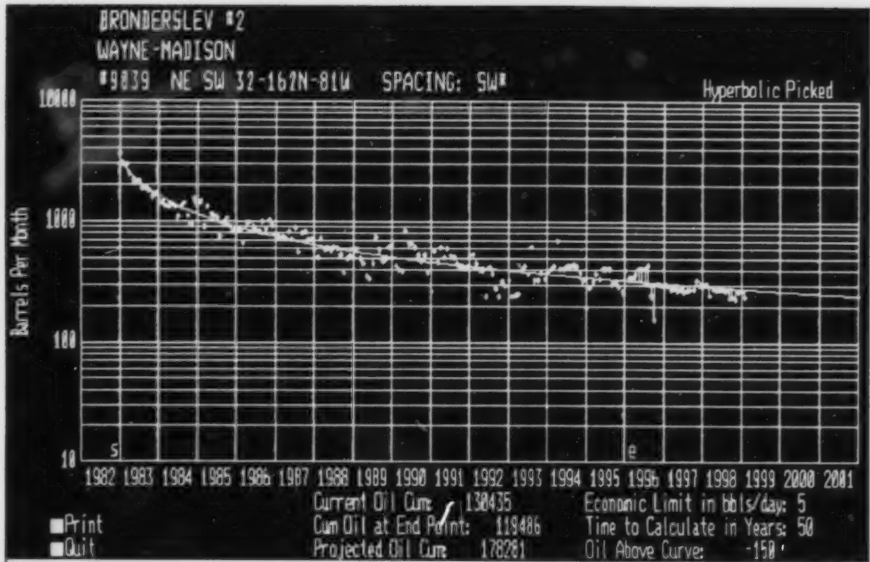
WAYNE MADISON POOL

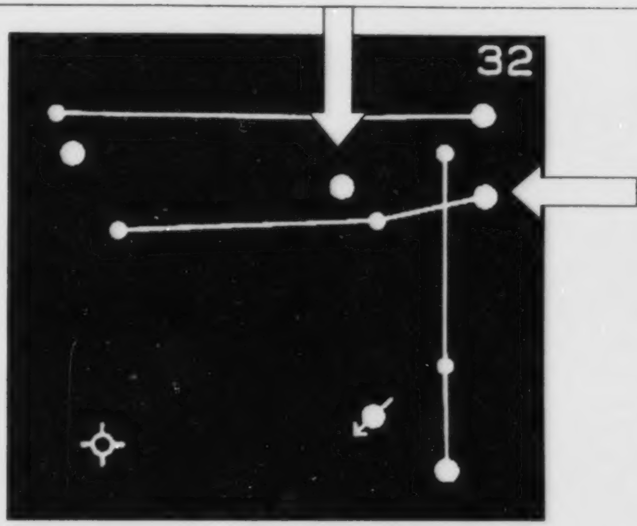


WAYNE-1

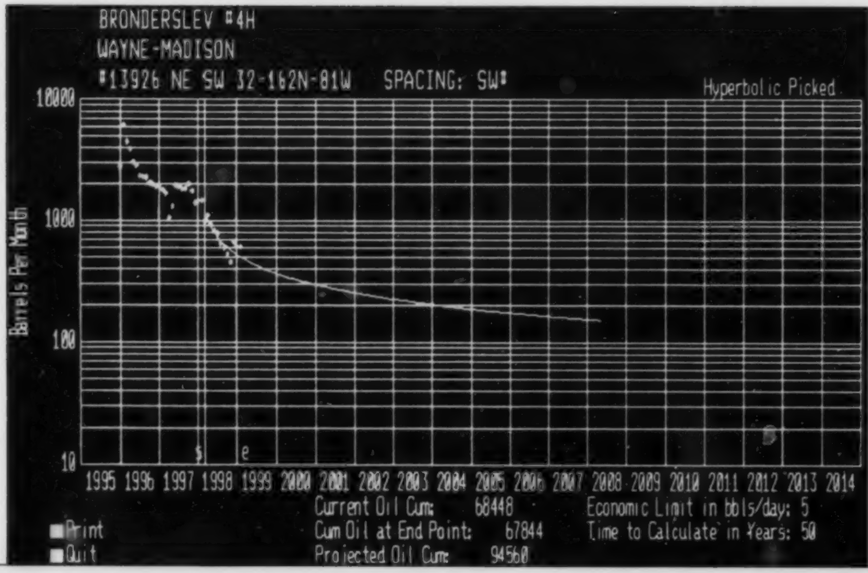


WAYNE-MADISON POOL

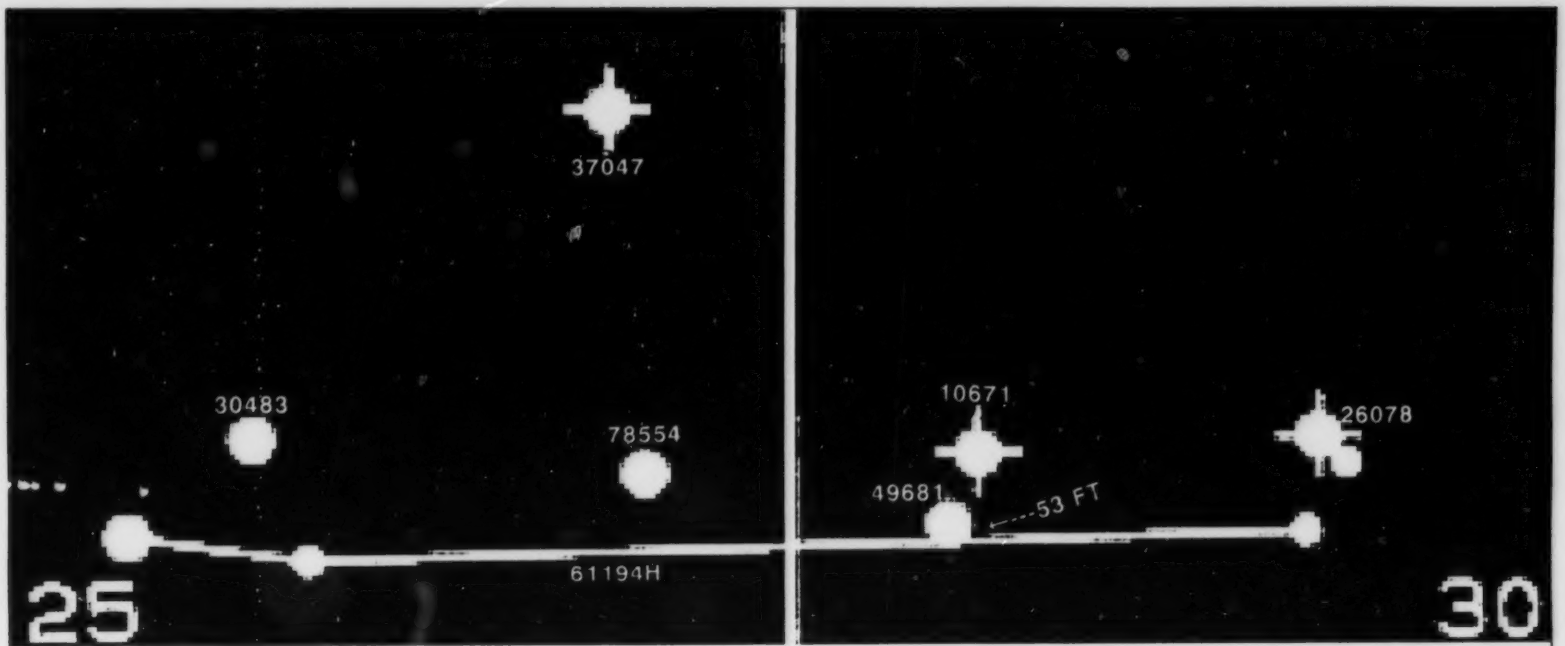




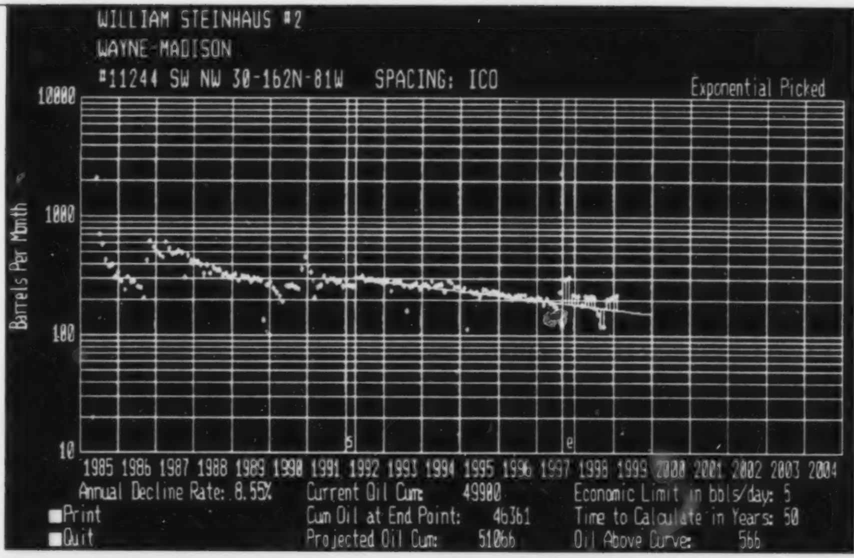
WAYNE MADISON POOL

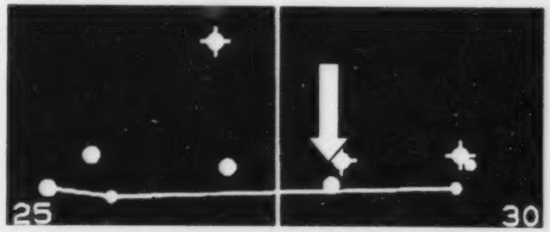


WAYNE-2

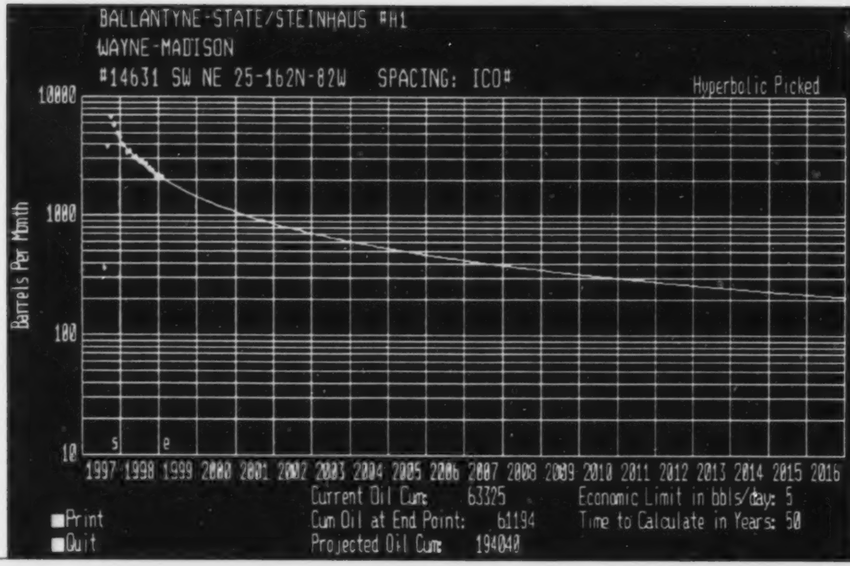


WAYNE
MADISON POOL

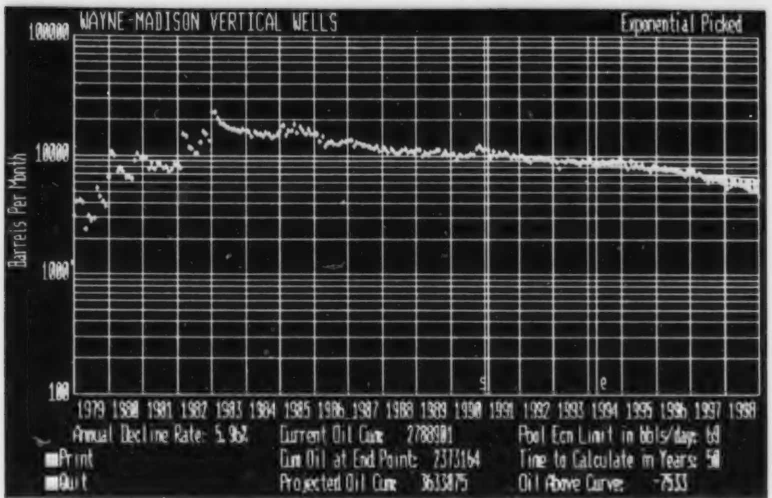




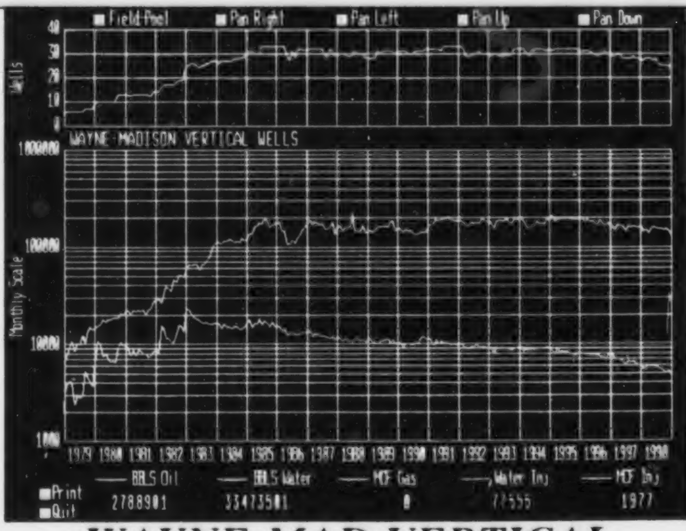
WAYNE MADISON POOL



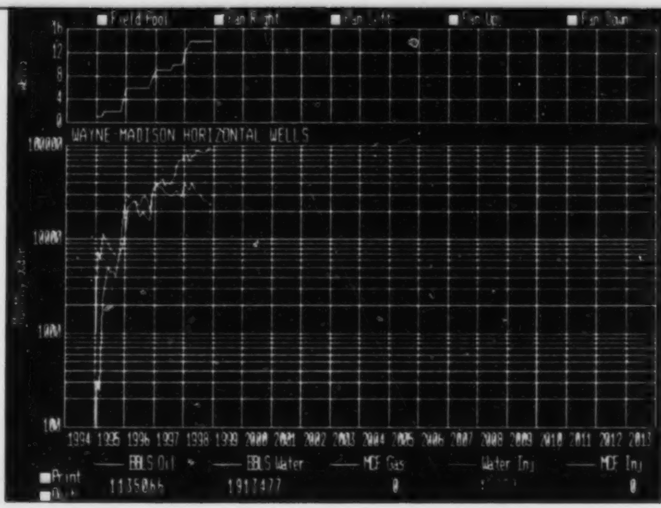
WAYNE-3



WAYNE-MAD VERT OIL



WAYNE-MAD VERTICAL



WAYNE-MAD HORIZONTAL

WAYNE-MADISON POOL

- FOURTEEN HORIZONTAL WELLS
- CUM = 1,157,784 BO (1-1-99)
- ROR = 1,135,000 BO
- INCREMENTAL = 2,293,000 BO
- EUR PER WELL = 164,000 BO

HORIZONTAL INFILL PRODUCTION

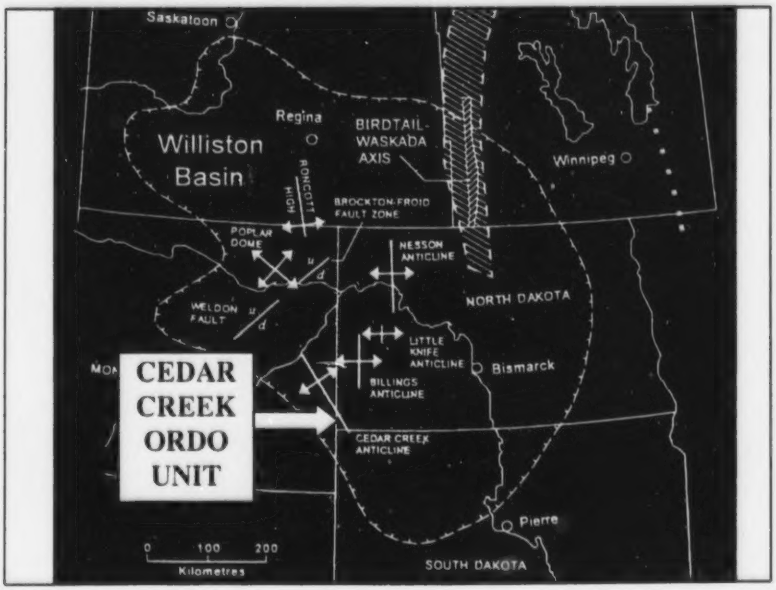
- **FOURTY-TWO HORIZONTAL WELLS**
- **CUM = 2,928,622 BO (1-1-99)**
- **ROR = 4,014,000 BO**
- **INCREMENTAL = 6,942,000 BO**
- **EUR PER WELL = 165,000 BO**

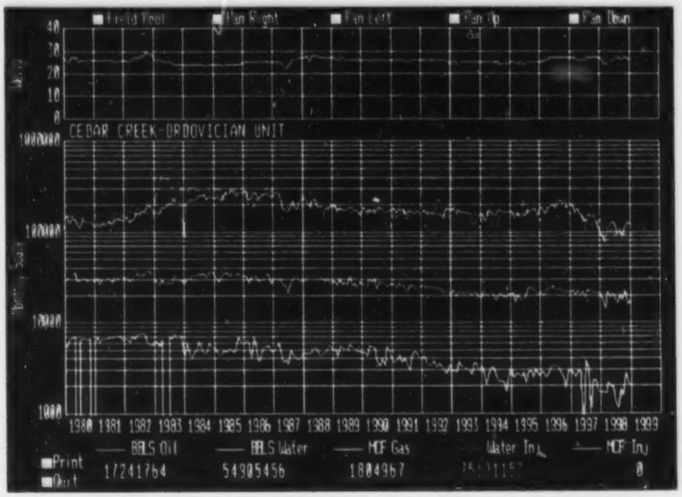
HORIZONTAL UNIT WELLS

Beaver Lodge-Madison Unit
Beaver Lodge-Silurian Unit
Cedar Creek-Ordovician Unit
Clear Creek-Madison Unit
Haas-Madison Unit
Horse Creek-Madison Unit
Little Missouri-Red River Unit
Medicine Pole Hills-Red River Unit
North Elkhorn Ranch-Madison Unit
Rival-Madison Unit
Tioga-Madison Unit
Wabek-Madison Unit

HORIZONTAL UNIT WELLS

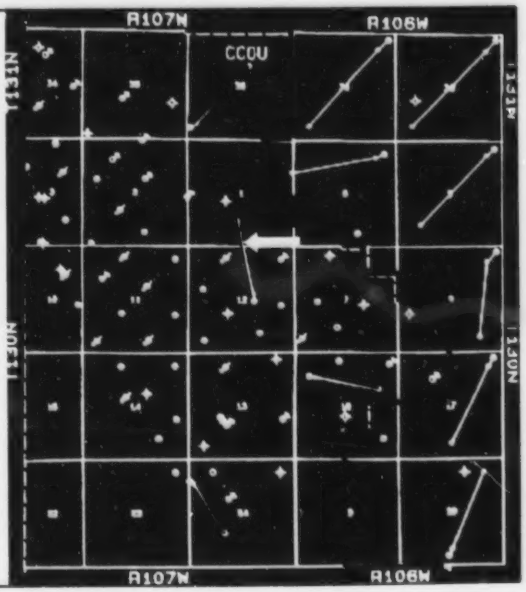
- Cedar Creek-Ordovician Unit
- Haas-Madison Unit
- Tioga-Madison Unit

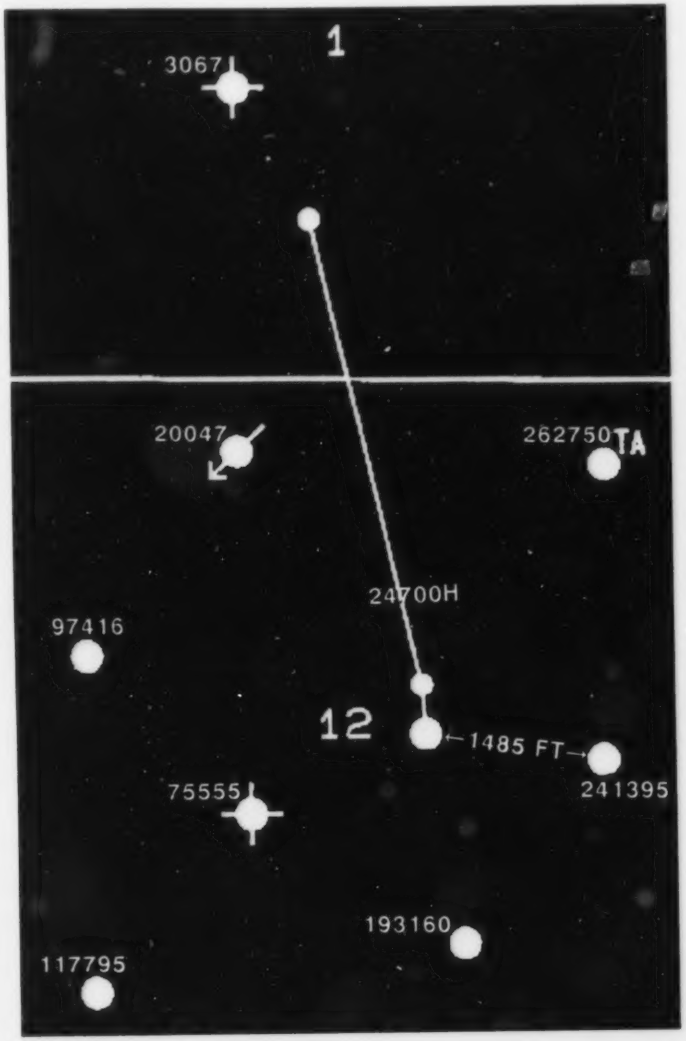




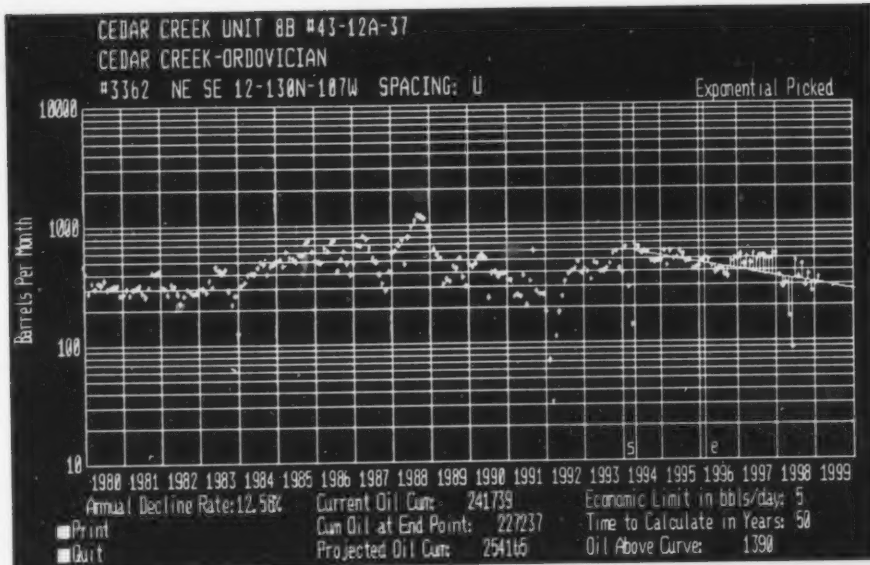
CEDAR CREEK-ORDO UNIT

CEDAR
CREEK
ORDO
UNIT

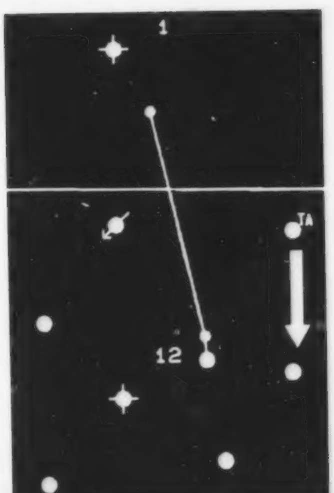


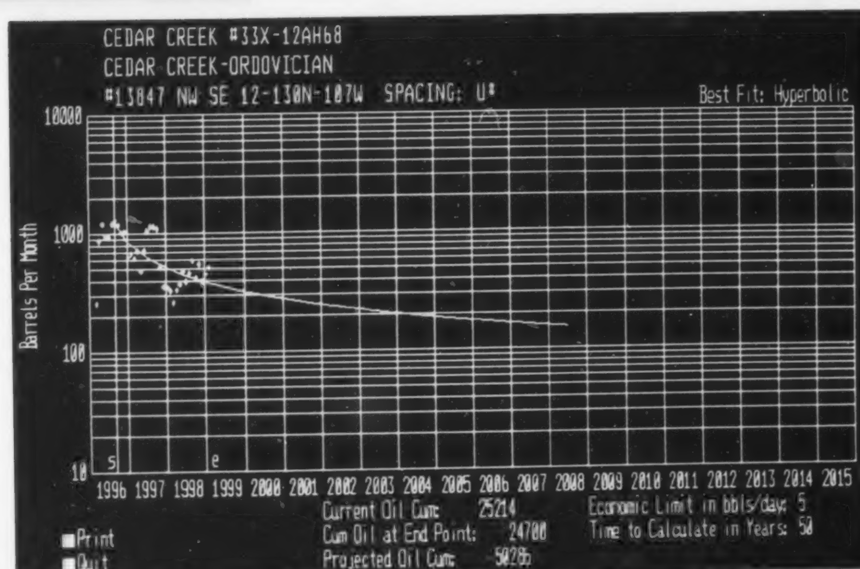


CEDAR CREEK ORDOVICIAN UNIT CUM OIL



CEDAR CREEK ORDOVICIAN UNIT

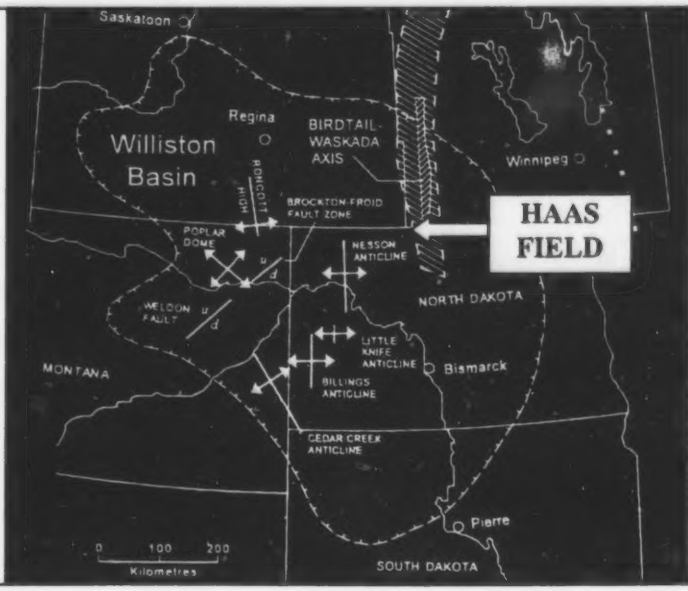


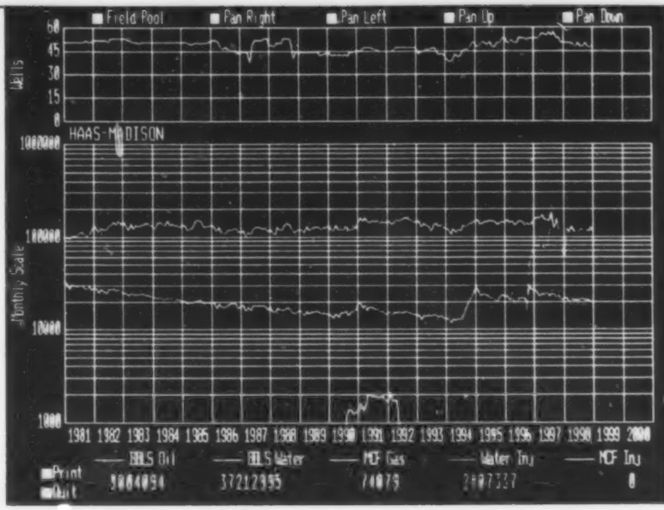


CCOU-1

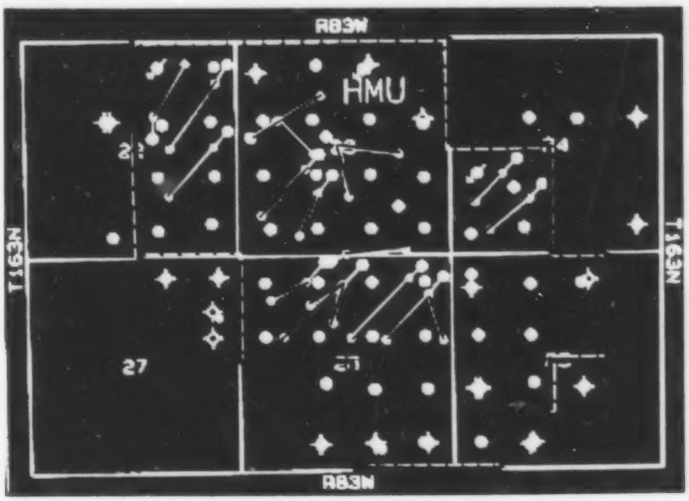
CEDAR CREEK ORDOVICIAN UNIT

- **FOUR HORIZONTAL WELLS**
- **CUM = 149,078 BO (1-1-99)**
- **ROR = 232,000 BO**
- **INCREMENTAL = 381,000 BO**
- **EUR PER WELL = 95,000 BO**

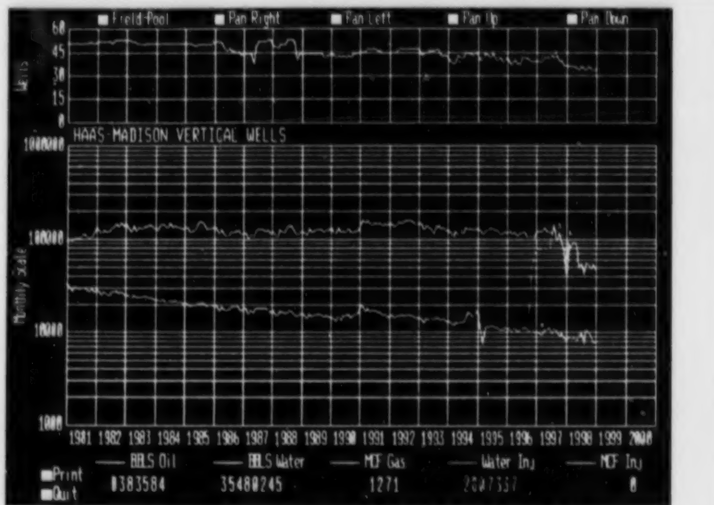




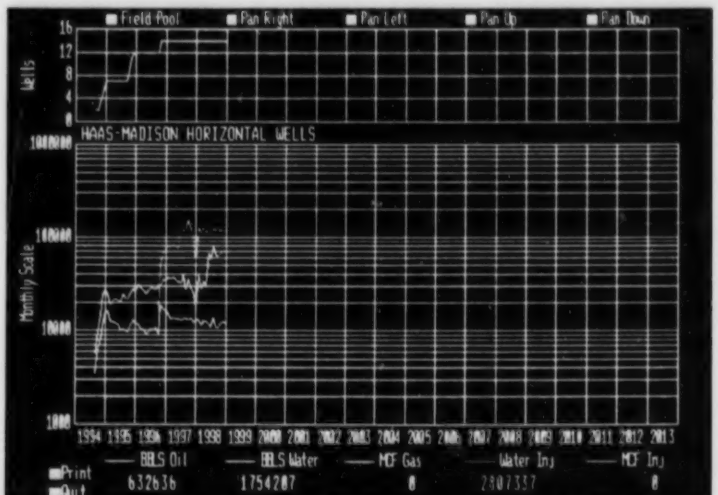
HAAS-MADISON POOL



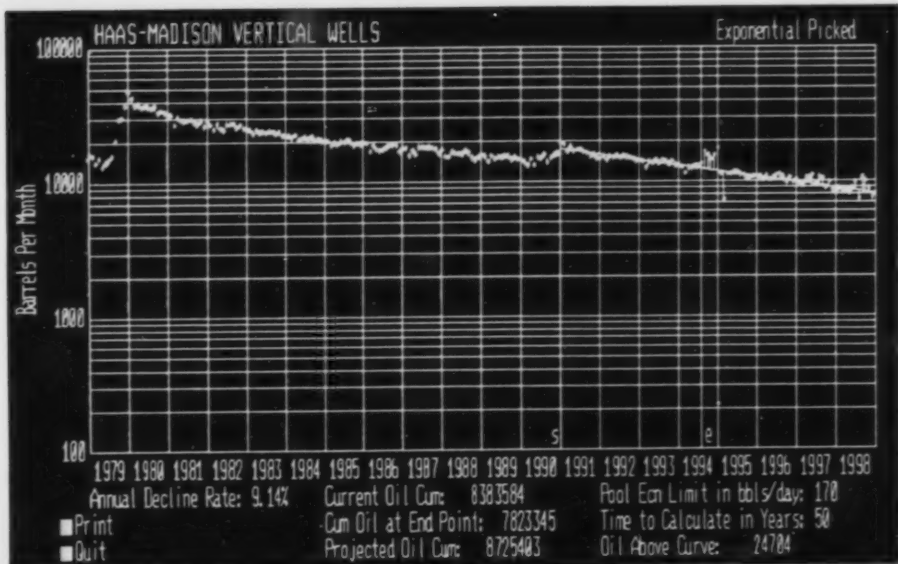
HAAS MADISON UNIT



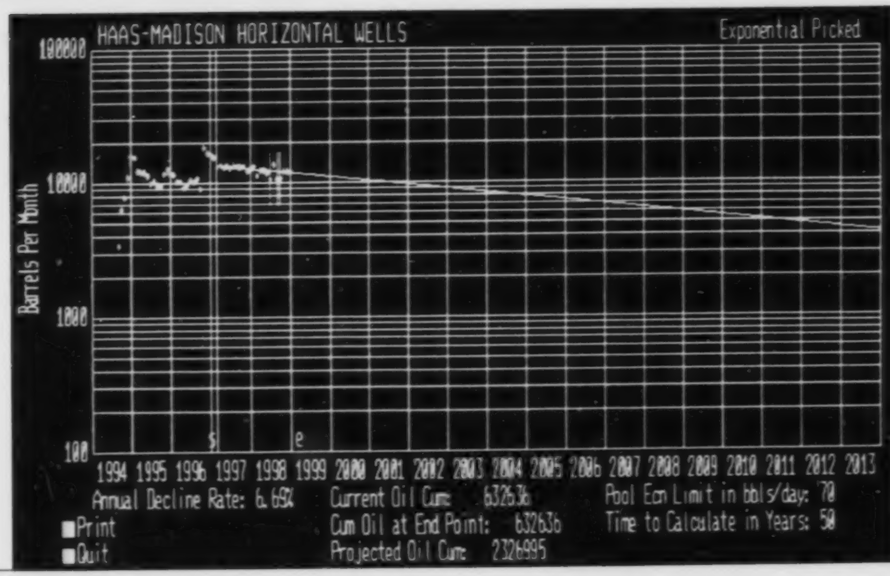
HAAS-MADISON VERTICAL



HAAS-MADISON HORIZONTAL



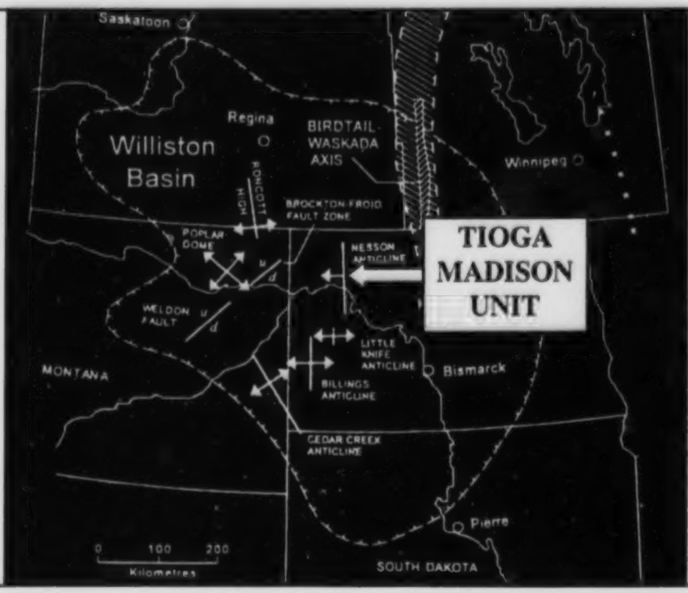
HAAS MADISON POOL

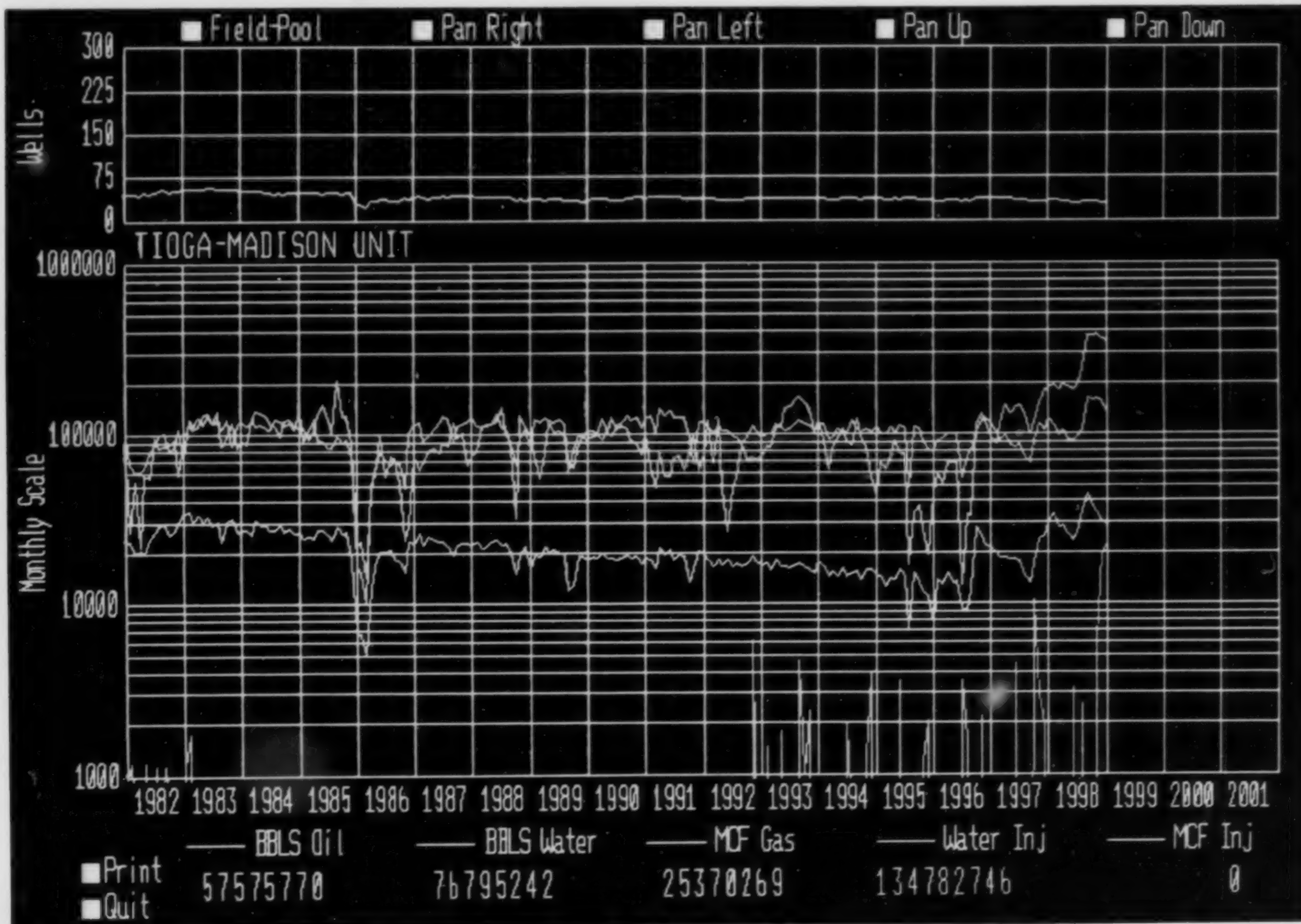


HMU-1

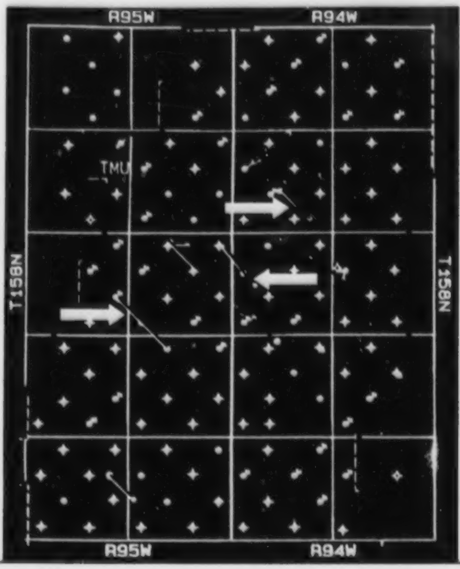
HAAS MADISON UNIT

- **FOURTEEN HORIZONTAL WELLS**
- **CUM = 632,575 BO (1-1-99)**
- **ROR = 831,000 BO**
- **INCREMENTAL = 1,464,000 BO**
- **EUR PER WELL = 105,000 BO**



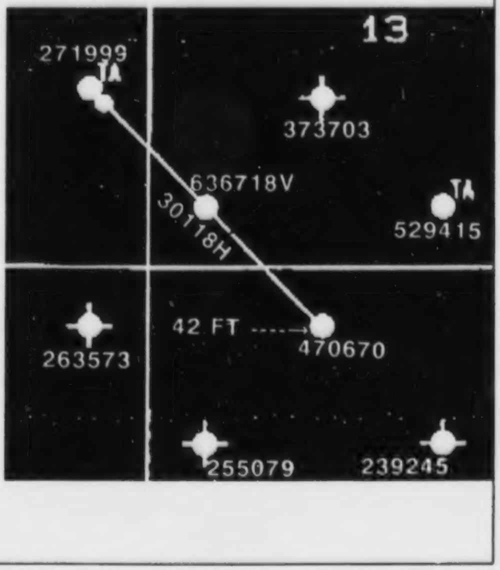


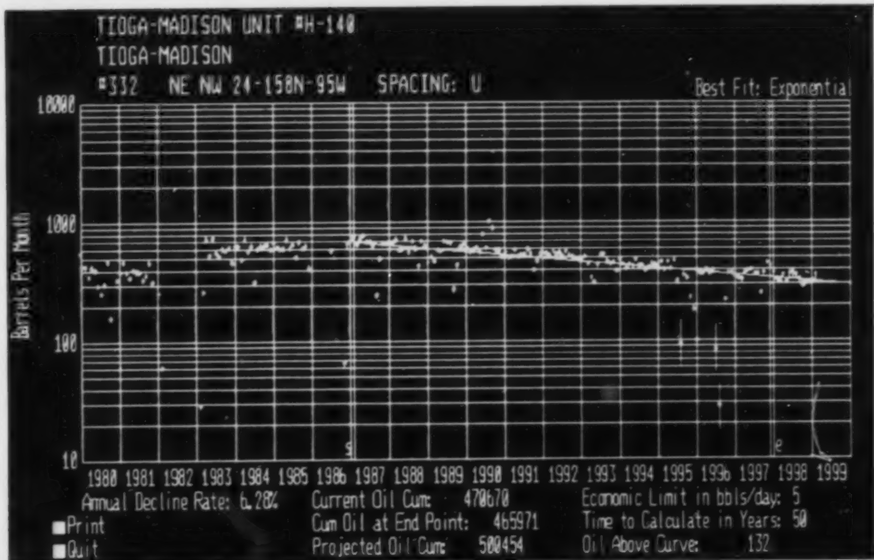
TIOGA-MADISON UNIT

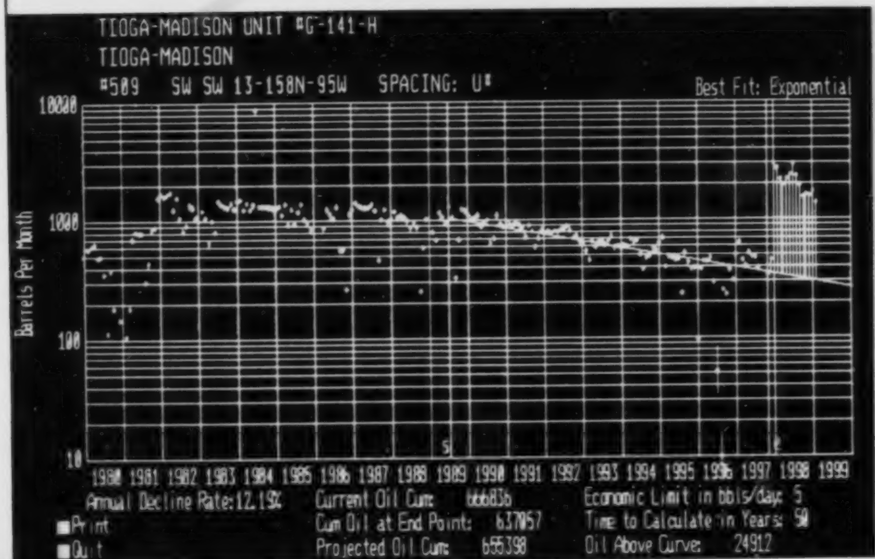


TIOGA MADISON UNIT

TIOGA MADISON UNIT CUM OIL







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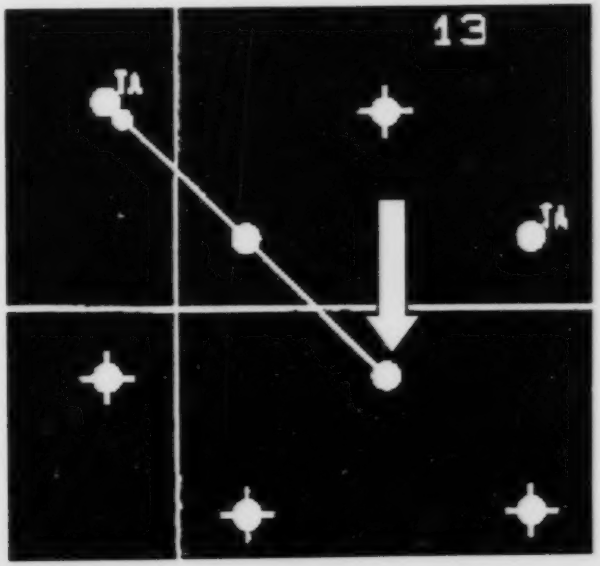
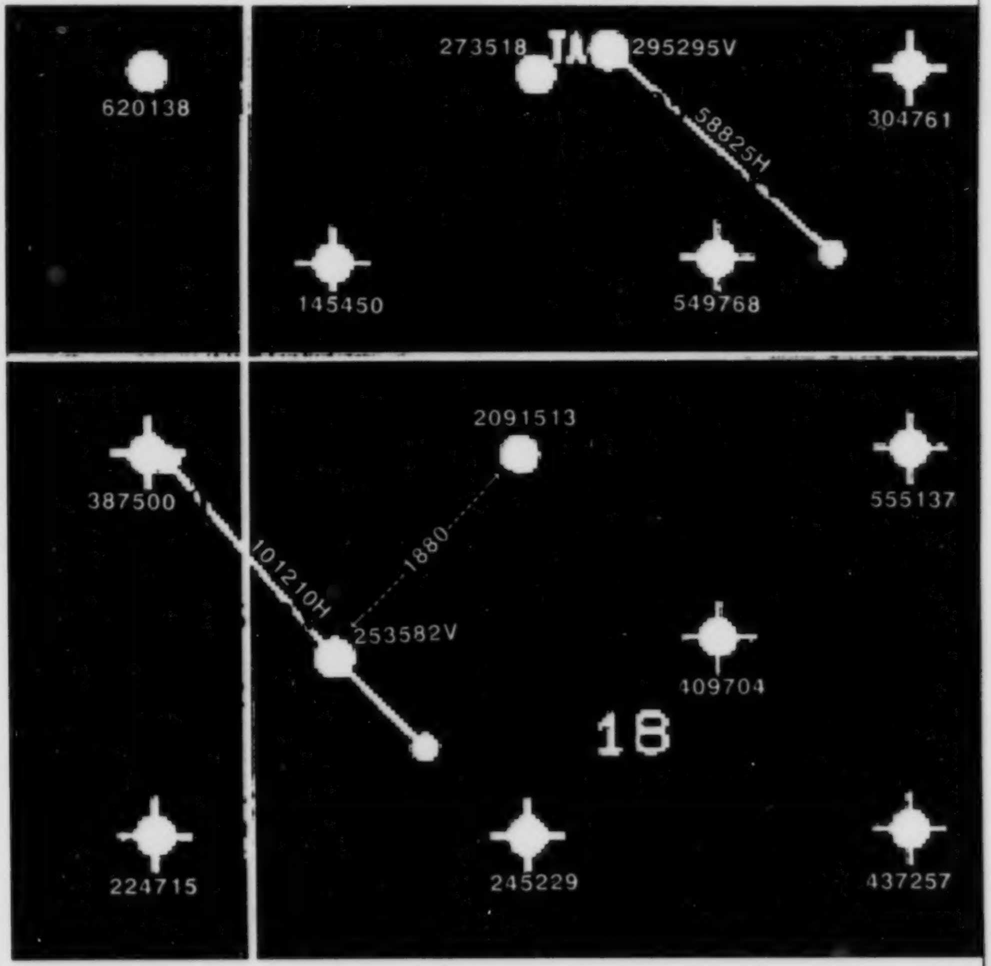


TMU-1

TIOGA MADISON UNIT CUM OIL



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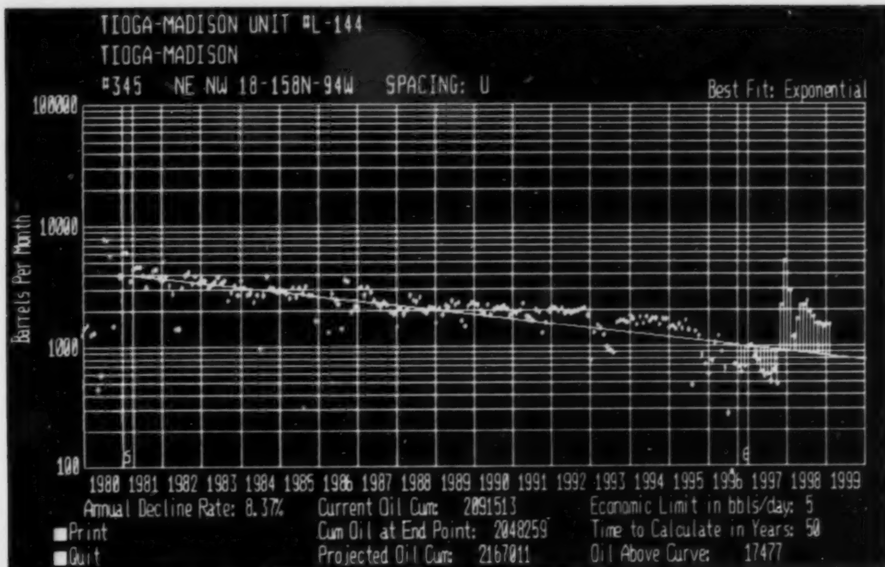
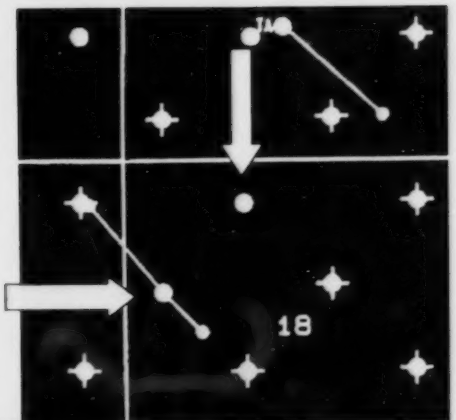
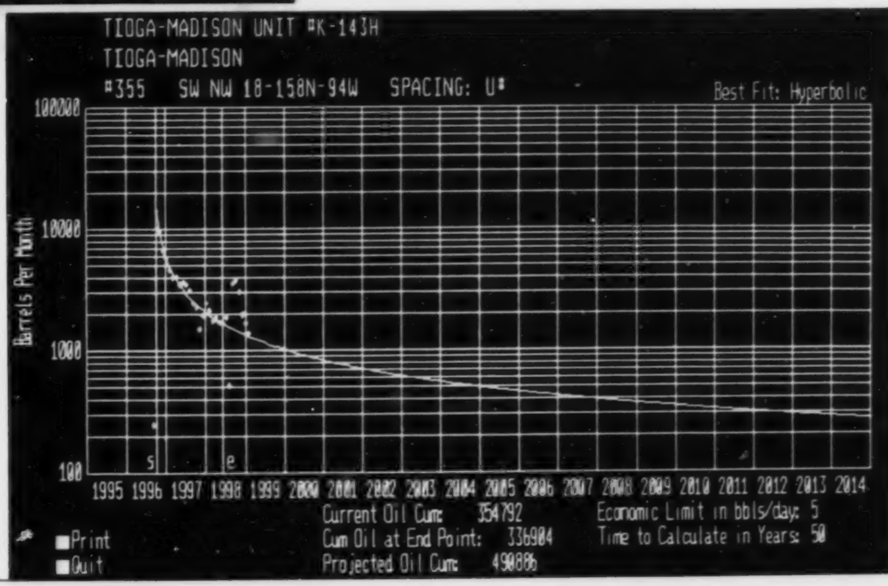
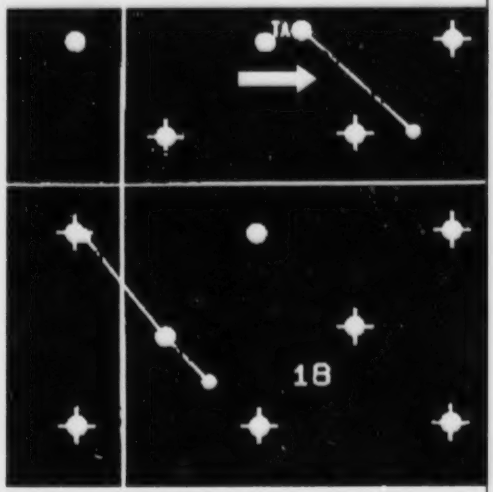


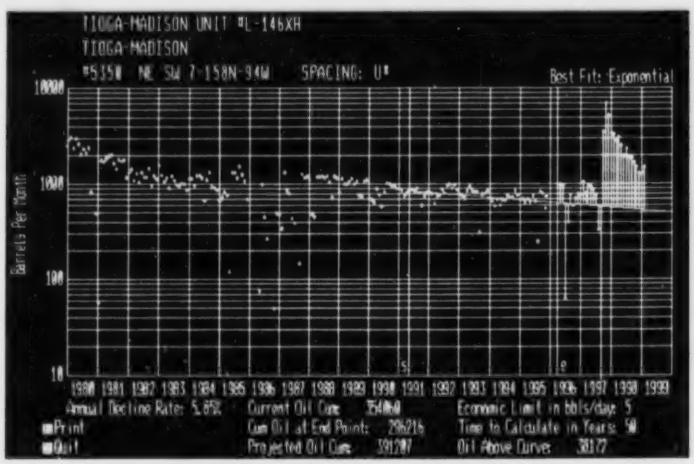




TMU-2

TIOGA MADISON UNIT CUM OIL





TIOGA-MADISON UNIT

TIOGA MADISON UNIT

- EIGHT HORIZONTAL WELLS
- CUM = 401,274 BO (1-1-99)
- ROR = 734,000 BO
- LOST VERT FROM RE = 129148 BO
- INCREMENTAL = 1,006,000 BO
- EUR PER WELL = 126,000 BO

HORIZONTAL UNIT PRODUCTION

- THIRTY HORIZONTAL WELLS
- CUM = 1,131,195 BO (1-1-99)
- ROR = 2,558,000 BO
- LOST VERT FROM RE = 247,000 BO
- INCREMENTAL = 3,442,000 BO
- EUR PER WELL = 115,000 BO

HORIZONTAL PRODUCTION
INFILL + UNIT

- **SEVENTY-TWO HORIZONTAL WELLS**
- **CUM = 4,059,817 BO (1-1-99)**
- **ROR = 6,572,000 BO**
- **INCREMENTAL = 10,385,000 BO**
- **EUR PER WELL = 144,000 BO**

A SIMPLE CORRELATION FOR ESTIMATING PRESSURE DROP IN A HORIZONTAL WELL

R. Islam
University of Regina

Abstract

Even though it has long been recognized that pressure drop along a horizontal wellbore cannot be neglected, little has been done to estimate the pressure drop with any rigor. The existing models are derived from pipeflow equations, neglecting, therefore, the presence of radial fluid movement perpendicular to the direction of bulk fluid flow. Recent experimental studies indicate that such a simplistic approach provides one with optimistic behavior in a horizontal wellbore. This paper presents a realistic representation of the pressure drop in a horizontal wellbore. Equations are derived from rigorous experiments conducted earlier and reported in the literature. They include the effect of radial fluid movement, perforation flow, gas-oil ratio, oil viscosity, bulk flow rate, water saturation, and even the presence of asphaltenes in the crude oil. Even though the equations are based on experimental results, predictions apply to field situations. This aspect is verified with certain unpublished field data, provided by operators in USA and Canada.

NUCLEAR MAGNETIC RESONANCE LOGGING

And

CONSIDERATIONS

For

HORIZONTAL WELLS

Brian J. Stambaugh

Abstract

Nuclear Magnetic Resonance (NMR) logging has gained increasing acceptance during the decade of the 90's. The capabilities of this technology in the area of formation evaluation are immense, but planning and executing an NMR job and interpreting the results are not trivial tasks. This is particularly true for horizontal wells. This paper describes the basic theory of NMR logging, discusses the currently commercially available wireline tools, reviews log examples and outlines the special considerations for planning an NMR logging job in a horizontal well.

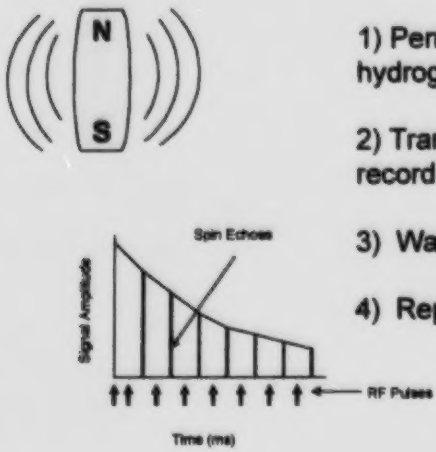
Outline:

- NMR Tool Theory
- Comparison of tool designs
- Log examples
- Special considerations for horizontal wells

NMR Tool Theory;

The NMR experiment involves two physical pieces of hardware;
1) A permanent magnet to induce polarization of nuclei.
2) An RF (radio frequency) antenna for manipulation of the nuclei and sensing the ensuing release of energy.

The Basic NMR Experiment



1) Permanent magnet polarizes hydrogen nuclei

2) Transmit train of RF pulses, record returning spin echoes

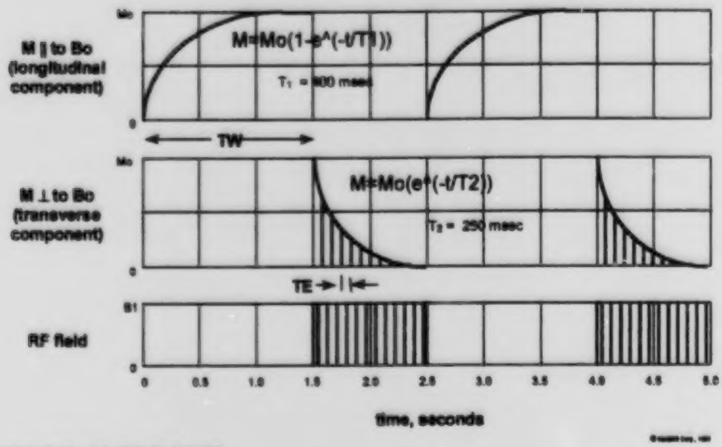
3) Wait for re-polarization

4) Repeat steps 1-3

The measurement involves three steps;
1) Polarization with the permanent field. The polarization involves an exponential buildup $e^{t/T1}$.
2) Manipulation with the RF field yielding spin echoes. The echoes have decay described by the function $e^{-t/T2}$.
3) The cessation of the RF field is followed by a period of re-polarization called wait time (Tw).

Two key pieces of information are contained in the echo train;
1) Extrapolating along the echo train back to time zero yields the ***NMR porosity***.
2) The ***echo decay rate*** described by T2 is a function of;
   - Pore size distribution. (Large pores -> long T2)
   - Fluid type (light oil -> long T2, heavy oil and gas -> short T2)
   - Relaxivity (carbonates -> lower relaxivity -> longer T2)

NMR Experiment Timing



adapted from Murphy, D.P., World Oil, April [illegible]

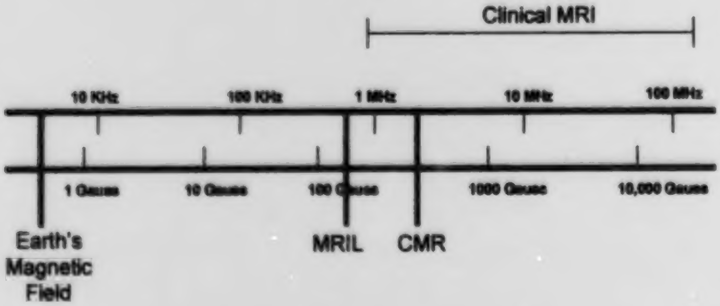
RF frequency is related to magnetic field strength for a given element via the Gyromagnetic Ratio.

F = (Gamma/2pi)*Bo

F is the RF frequency, Gamma is the Gyromagnetic Ratio

Bo is the magnetic field strength

Relationship of Magnetic Field Strength to Frequency



$$F = \gamma B_0$$

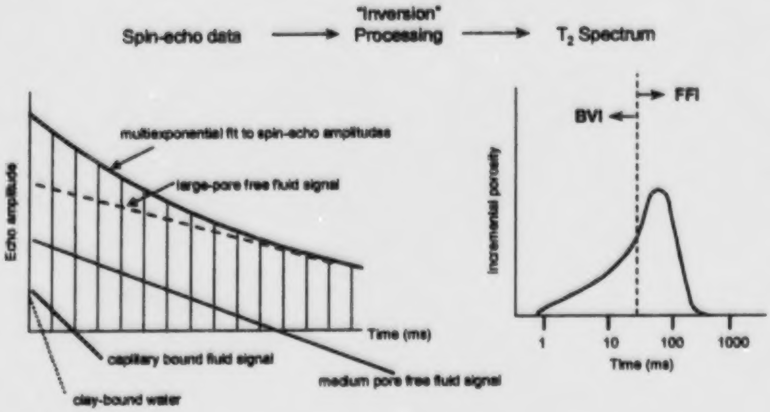
Proton "spin" rates are proportional to Magnetic Field Strength.

For Hydrogen: γ = 4258 Hz / Gauss

F = Frequency (Hz)

B_0 = Field Strength (Gauss)

Echo to T2 "Inversion"



NMR tools measure echo amplitude and phase. The echo data may contain various decay rates reflective of various pore sizes and fluid interactions. The echo data is converted to a description of the decay rates called a T2 distribution. The conversion of echoes to T2 is called "inversion" processing. The T2 distribution may be shown as a wiggle trace (similar to that above), or as a variable density (VDL) display. It may also be shown as porosity "bins". The bins are discrete slices of T2 data. For example the log may show T2 bins at 4, 8, 16, 32, 64, 128, 256, and 512 ms. The example above would have high amplitude in the 64 and 128 ms bins since that is where the T2 peak is, but not much in the 4 or 512 ms where there is relatively little amplitude. Inversion processing is referred to, as an under-determined mathematical problem since the number of T2 "bins" being solved for is greater than the number of independent pieces of information that are available. Inversion results may vary with;

1) Signal to noise ratio (running average), although service companies try to hold this to a standard by changing the logging speed.
2) The regularization term alters the result for MRIL processing.
3) The beginning echo – including the first echo can result in higher BVI for example.
4) Application of noise filters and phase correction.

NMR porosity is simply the summation of the area under the T2 distribution. It is independent of matrix effects since the porosity is a reflection of the hydrogen content. However NMR porosity can read too low in the presence of light hydrocarbons since it is a "hydrogen count" porosity. It will also read less than the total porosity if the wait time (Tw) was insufficient or in the presence of materials having a very low T2 value such as clay bound water or heavy oil.

The Meaning of T2 Distributions

The measured T2 (T2R) is a summation of surface T2, bulk T2 and T2 of diffusion.

$$1/T2R = 1/T2S + 1/T2B + 1/T2D$$

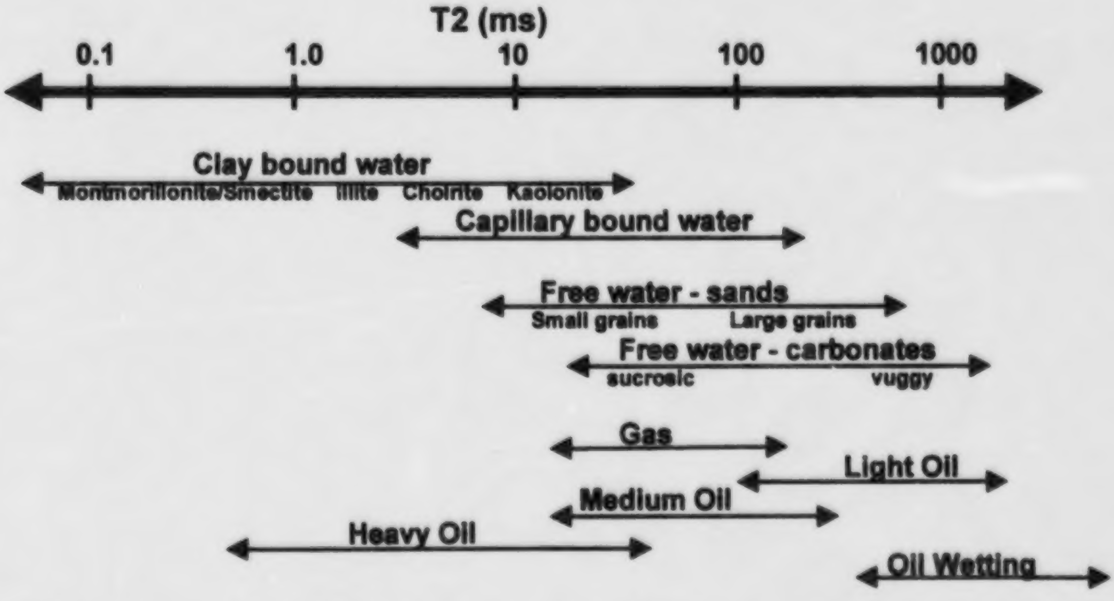
T2S (surface) is the dominant relaxation mechanism for water filled pores in water wet rocks. For water filled pores in water wet rocks T2S is related to surface to volume ratio and governed by surface relaxivity (surface mineralogy governed) by the equation;

$$1/T2S = \rho(S/V)$$

where ρ is surface relaxivity, S is the pore surface area, V is pore volume

T2B (bulk) is controlled by the precessing protons interacting with neighboring protons and is governed by the fluid properties. It has been shown that T2B is directly related to oil viscosity for example. The movement of precessing protons from one location in space to another governs T2D (diffusion). This is the dominant relaxation mechanism for gas and is a function of inter-echo spacing (Te), gyromagnetic ratio, and gradient (G).

$$1/T2D = D/12*(Gamma*G*Te)^{\wedge}2$$



The T2 continuum above is meant to describe in a qualitative sense where T2 values may lie for various rock and fluid types. An important point is the variability of the boundaries for clay and capillary bound water and for the oils. Thus the need for core and fluid analysis.

Computing Bulk Volume Irreducible (BVI) and Permeability

Capillary bound fluid or Bulk Volume Irreducible (BVI) can be computed from the T2 distribution by using methods such as;

1) Cutoff Method; 33 ms for sands, 90 ms for carbonates etc. With this method, all of the porosity associated with a T2 less than the cutoff value lower than the cutoff value is considered to be bound fluid. This method was found to give a low estimate of BVI in some situations, for example, where there were mechanisms at work pushing the average T2 value too high.
2) Spectral Methods; With this method, a portion of each T2 bin comprises BVI. These methods include; Spectral BVI model – (Halliburton), Film BVI model (Baker Atlas), and Tapered BVI model (Schlumberger).

Permeability can be computed from methods such as;

1) Coates Bound Fluid Equation; Computed from porosity and FFI/BVI ratio. The perm result will read too low if the NMR porosity is affected by light hydrocarbons.

PERM = (((MPHI/A)^B) *(MFFI/MBVI)^C

Where;
MPHI is the NMR porosity (If MPHI is affected by light hydrocarbons, clay corrected neutron-density porosity (Phie) may be substituted.)
MFFI is the NMR free fluid volume (If MPHI is affected by light hydrocarbons, then Phie-MBVI may be substituted.)
MBVI is the NMR bound fluid volume
A is usually 10 in soft rocks and 16 in hard rocks, B is usually 2, C is usually 2

2) T2 or SDR Perm; Computed from the porosity raised to a power times the mean T2 raised to a power.

SDRPERM = A*((CMRP)^B)*((T2LM)^C)

Where;
CMRP is the NMR porosity
T2LM is the log mean T2
A is usually .000002, B is usually 4, C is usually 2

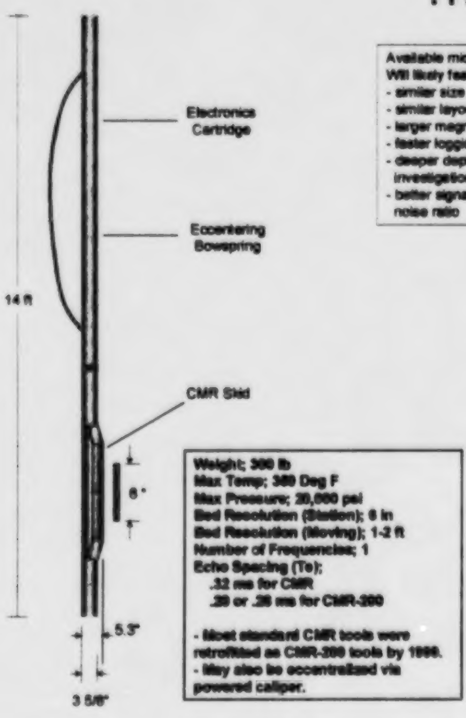
BVI and permeability coefficients should be refined with core measurements, particularly in carbonates and older rocks.

Comparison of NMR Tool Designs

CMR

- A pad mounted tool, 14' long, 300#, 5.3" diameter
- Combinable with most SWS tools.
- Better bed resolution than MRIL (1-2'), but more sensitive to hole rugosity.
- A good BVI tool in smooth boreholes.
- Not nearly as sensitive to saline mud as the MRIL.
- Logging speed much slower (3-5x) than the MRIL C tool for the same wait time (Tw).
- Advanced applications such as shifted and differential spectrum are do-able but not in a practical sense. Comparison with density porosity is the preferred method of direct hydrocarbon identification.
- Total porosity logging has no significant speed penalty.
- SWS offers "Bound Fluid Logging" at high speeds but this is dependent on modeling other porosities to create effective porosity.
- Focused field creates tuning issues downhole.
- Calibration and mud checks are simple with a small fixture.
- More of a supplement to conventional tools.

CMR and CMR-200

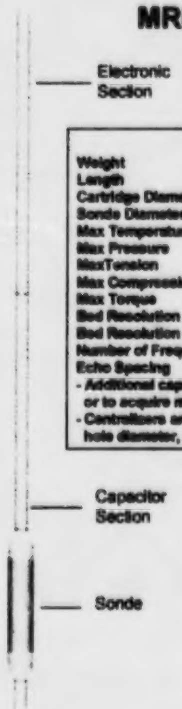


CMR "Next"
????

MRIL

- Mandrel type tool, 50+ feet long, 1000+ lbm, 4.5, 4 7/8" or 6" diameter
- Combinable with most AWS, Computalog and HLS tools
- Combinable with SWS tool strings (sequential logging) via a switching sub.
- Lower bed resolution (3-7'), much less sensitivity to hole rugosity.
- Saline muds cause much lower logging speeds, sodium resonance can be an issue.
- Large sensitive volume and gradient field results in superior performance in advanced applications such as shifted and differential spectrum.
- Downhole tuning is simple but calibration is via a large "Faraday cage" – more clumsy than with the CMR.
- Total porosity logging offers better signal to noise than CMR but has a speed penalty with C tool.
- Embodies the hope of replacing other (neutron-density) logs.
- D "Prime" tool offers advanced applications at 24 ft/min.

MRIL C and D (Prime)

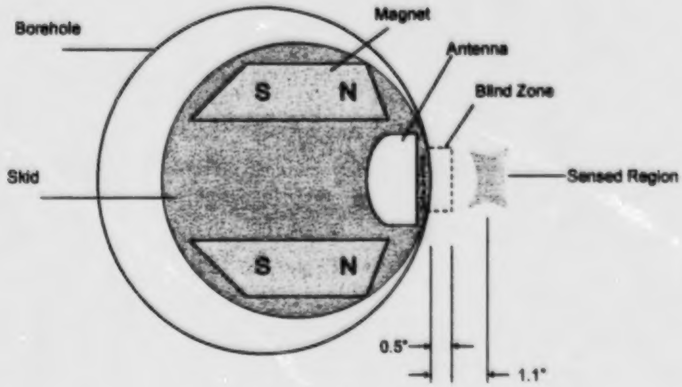


	C Series	D (Prime) Series
Weight	1000 lbs	1200 lbs
Length	47.5'	60.5'
Cartridge Diameter	3 5/8"	3 5/8"
Sonde Diameter	6 or 4.5"	6 or 4 7/8"
Max Temperature *	310° F	350° F
Max Pressure	20,000 psi	20,000 psi
MaxTension	60,000 lbs	35,000 lbs
Max Compression	35,000 lbs	35,000 lbs
Max Torque	200 ft-lbs	1000 ft-lbs
Bed Resolution (station)	24 in	24 in
Bed Resolution (moving)	3-7 ft	3-7 ft
Number of Frequencies	3	9
Echo Spacing	0.6 ms	0.6 ms

- Additional capacitor sections may be used in saline muds or to acquire more echoes.
- Centralizers and/or standoffs may be used depending on hole diameter, deviation etc.

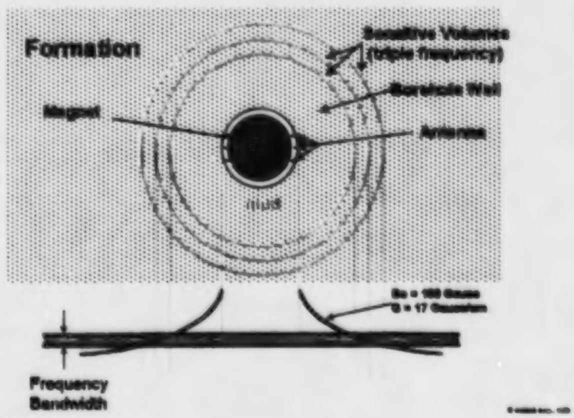
MRIL was developed by *Numar*. *Numar* was purchased by *Halliburton* in 1997. MRIL tools are under license to *Baker Atlas* (C and D tools) and Computalog (C tool only).

CMR Sensitive Volume



The CMR was designed to have a focused field. As it turns out, the center of the sensed region is non-gradient but the "horns" have a steep gradient. This results in an effective gradient of 20 G/cm. The focused field design means that there is not the potential for multi-frequency operation as with the MRIL. The focused field also means that the tool must be operated in a very small frequency window in order to have resonance within the focused field. This results in the need for re-tuning downhole as the static field strength changes with temperature.

MRIL Sensitive Volume



The MRIL has a gradient field allowing operation at multiple frequencies. If the frequency is decreased by a few kHz, then resonance occurs at slightly lower field strength, which is present a bit farther from the tool. The diagram above depicts operation at three different frequencies, which results in sensitive volumes in three concentric shells surrounding the tool. In practice, the shells are about 1 mm thick and 1 mm apart with a frequency spread of 24 kHz. Operation at multiple frequencies allows faster logging. This type of gradient also simplifies the task of "staying on frequency as the magnetic field strength changes with temperature.

Wait Time – CMR vs. MRIL;

A key parameter in NMR logging is Wait time or Tw. This is the time allowed for re-polarization of the nuclei prior to the next series of RF pulses. Wait time for full polarization may need to be 0.3 second for clay or silt dominated rock to 30 seconds for high porosity sand or carbonate with light oil or gas in the pores or oil wetting. Polarization time is governed by the equation;

Amplitude = e^(t/T1)

Tw is generally set such that Tw = 3* T1, which achieves 95% of total polarization. So... T1 can range from a few ms for clay to several seconds for the above oil or gas situations. You might have noticed that this correlates somewhat to the range of T2. In fact a study was performed (Kleinberg et al 1993) that demonstrated that for a large number sandstone samples T1 = 1.5*T2 (approximately). The following table illustrates some commonly observed Tw settings that would be needed to obtain full polarization. In practice Tw settings greater than 8 seconds are not used due to the logging speed penalty. <u>This table should not be used as a substitute for a proper Tw check in a given well. It is only meant to illustrate the effect of different fluid and rock types on the Tw.</u>

Formation and fluid	Tw needed for full polarization (seconds)
Clay	<0.1
Silt	0.3
Tight sands – wet	0.3 – 3
High porosity sands – wet	2 – 5 or greater
Carbonates – wet	2 – 6 or greater
Gas saturated formations	5 – 20
Formations saturated with heavy oil	< 1 – 3
Formations saturated with light oil	5 - 20
Oil wet formations	10 - 30

The penalty for setting Tw too low is a low porosity reading. However, the longer the Tw, the slower the logging speed. In gas or light oil reservoirs it would be impractical to log with the needed long Tw and slow logging speed. Different service companies have different strategies for accommodating this problem. The strategies involve either using the correct Tw or to use a shorter Tw for faster logging along with making a "polarization correction" or "T1 correction" which estimates the porosity that would have been achieved if the correct Tw were used. Note that the correct porosity may still not be achieved in the presence of light hydrocarbons because NMR porosity, like neutron porosity, may need a hydrogen index correction.

Schlumberger;

1) Use the full wait time needed or close to it – say 1.5-4 seconds. This has been referred to as "Full Acquisition Mode" by SWS. Schlumberger uses this type of pass for the DRM method of gas identification. It involves comparison of density porosity to NMR porosity. This results in a slow logging speed (200-500 ft/hr) but a good direct indication of free fluid albeit one that may still need T1 and hydrogen index correction.
2) Use an intermediate Tw, 1.2 seconds for sandstone and 2.4 seconds for carbonates. This results in a faster logging speed, 300-600 ft/hr but requires a T1 correction (referred to as polarization correction) to achieve the correct porosity.
3) Use a very short Tw such as 0.3 seconds. This allows a logging speed of 900-3600 ft/hr. With this method, primarily the bound fluid volume is observed, thus the name "Bound Fluid Logging". No attempt at T1 correction is attempted. The free fluid volume is taken as the difference between the clay-corrected external (usually neutron-density) porosity and the NMR porosity. There have been cases

MRIL;

1) If a differential spectrum pass is being recorded (two files with different wait times), a T1 correction can be made based upon the porosity difference between the two wait times.
2) If a normal single Tw data set is recorded, an attempt is made to locate a clean water wet high porosity zone in which to perform a T1 check. The wait time is set in this zone and used through the entire interval.

Bed Resolution – CMR vs. MRIL;

The CMR has a bed resolution advantage in bed thickness between 1-2 feet and 4-5 feet. Both the MRIL and CMR tools suffer in beds thinner than 1-2 feet. Both do fine in beds thicker than 4-5 feet. Consider a thick sand-shale sequence with porosity = 30%, BVI = 10% and porosity = 0% with height = 1 inch. Both tool designs will return a correct average free-fluid porosity volume of 15% (the average of 0 and 30%). If the height is changed to 2 feet, the CMR will correctly resolve the free fluid porosity and perm. The MRIL will yield the correct average free fluid volume but incorrect FFI/BVI ratio and perm. If the height is 5 feet, both the CMR and MRIL will yield the correct average free fluid porosity volume, FFI/BVI ratio and perm, although the CMR will have less bed boundary effects. In essence, both tools provide a good volumetric net to gross number (subject to correction for incomplete wait time and light hydrocarbon effects but the perm resolution suffers. Possibilities exist for deconvolution using data from higher resolution measurements such as FMI, SFL etc.

NMR Log Products and Examples

NMR Log Products

- NMR answers fall into two main categories;

1) Reservoir characterization including total and effective porosity, BVI, perm, pore size distributions, clay characterization, etc.
2) Fluid characterization including direct hydrocarbon typing or detection and viscosity estimation.

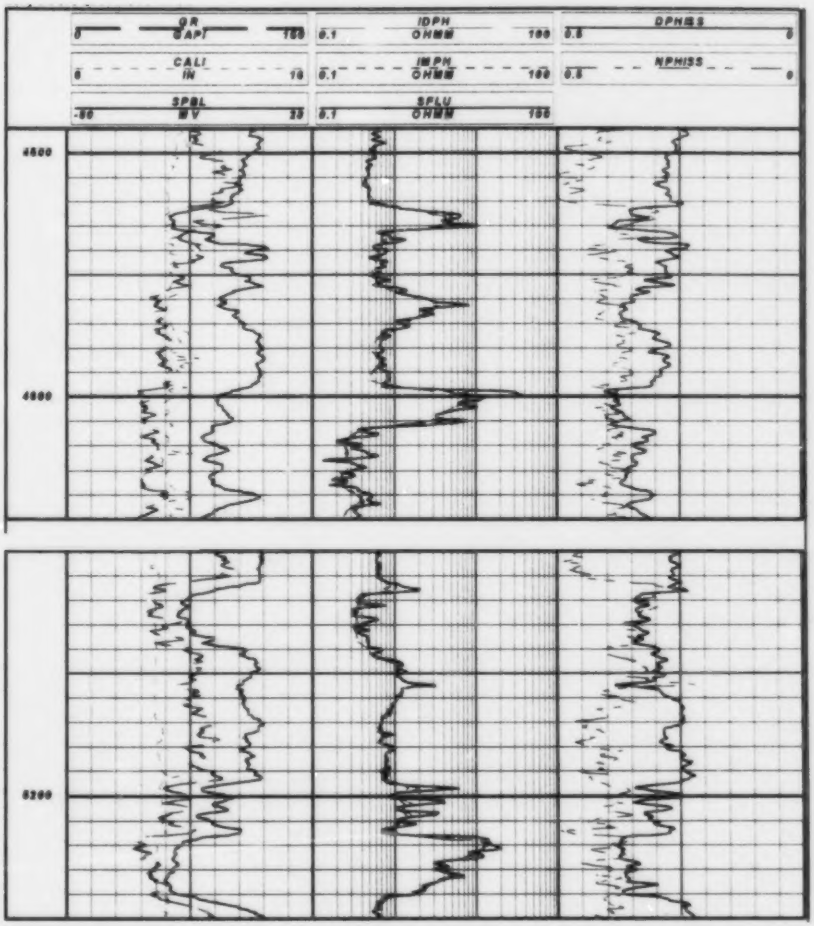
- ***NMR field log*** presentations generally include NMR porosity, bound fluid or free fluid, perm and a T2 distribution either as a wave or VDL display and/or as porosity bins.

- ***Basic computed logs*** such as CMR Quicklook/ELAN, MRIAN, MRAX offer a breakdown of the free fluid volume into hydrocarbons and free water – and also perhaps refinement of T2 cutoffs and perm models. These models are all subject to the old rule of garbage in, garbage out. Clay bound water estimates, m and n (or w), and Rw are keys to a valid product. Core analysis for determination of NMR T2 cutoff values for capillary bound water, electrical properties, clay characterization via Xray Diffraction and SEM are all valuable aids to the generation of a meaningful computed product. Total porosity NMR data is a valuable input but should be correlated to SEM and XRD core data.

- ***Advanced computed products*** include direct or semi-direct shallow zone fluid identification. These techniques provide the advantage of fluid identification independent of resistivity and associated parameters but it must be remembered that they are only detecting the residual shallow zone saturation. These techniques include;

1) Time Domain Analysis (TDA) (Prammer, et al 1995) for the MRIL; Uses "Differential Spectrum" (multi Tw) data (Akkurt, et al, 1995). A very good product for "imaging" hydrocarbons (primarily gas) without dependence on Rt, m, n, Rw, Vclay etc. The amount of residual gas available for measurement in the sensed volume of the MRIL is described by the term delta-phi-h which must be greater than 1.0 p.u. in order for TDA to work properly. This rules out very low pressures, and/or very low porosities, and/or very complete flushing.
2) Density Ratio Method (Freedman, et al 1998); SWS method of comparing CMR porosity to density porosity for gas identification.
3) Shifted Spectrum (Akkurt, et al 1995); Uses multi (echo spacing) Te data. Very successful commercial application where resistivity has failed and in certain oil viscosities (1-30 cp.). Primarily an MRIL product.
4) Enhanced diffusion or EDM; (Akkurt, et al, 1998) A dual TW method using a longer Te to enhance the visibility of the oil signal. This technique shows great promise in direct fluid identification for light oil (viscosity between 1 and 100 cp.).

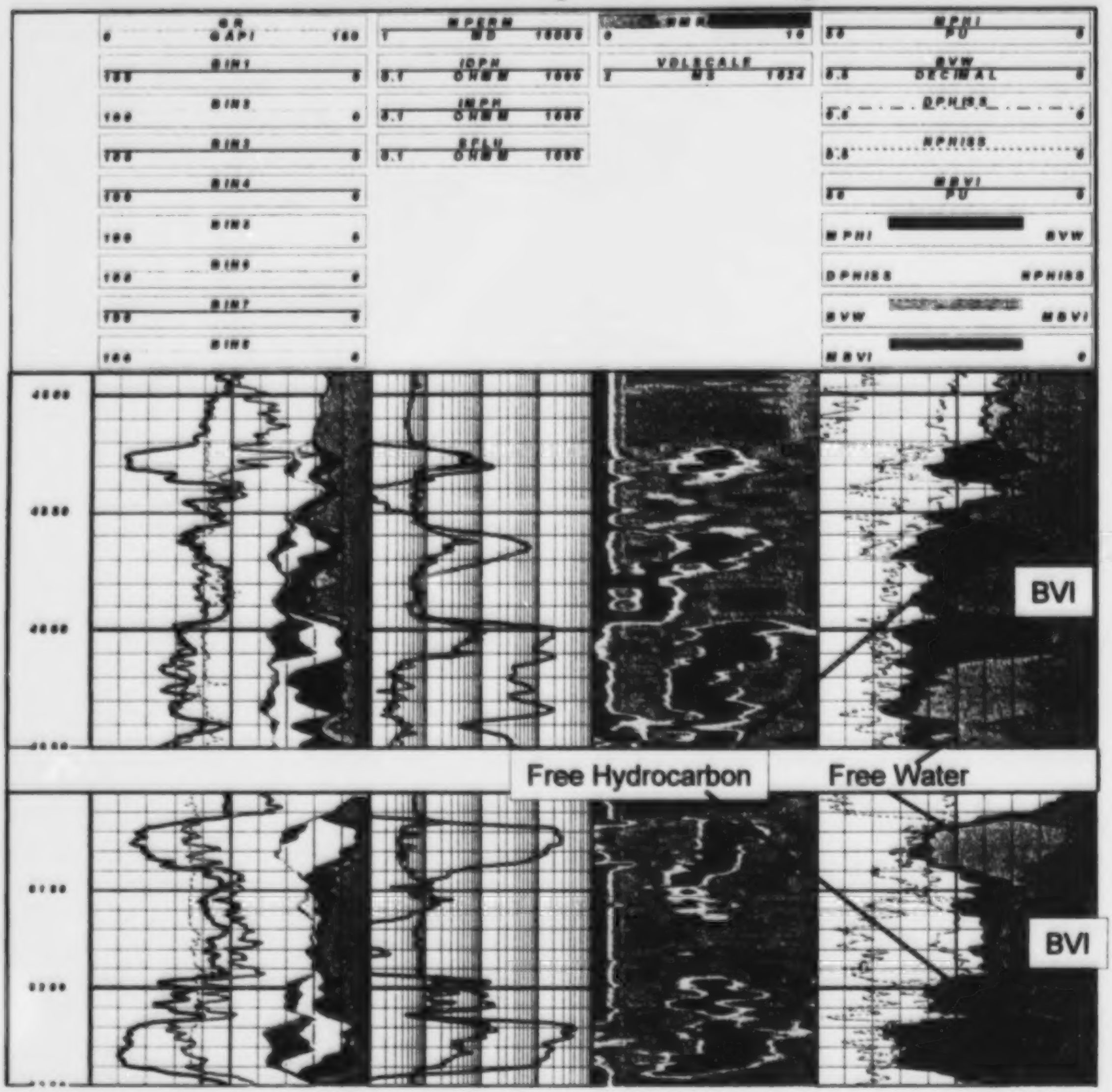
Triple Combo Log - Shaley Sand



NMR Petrophysics Inc.

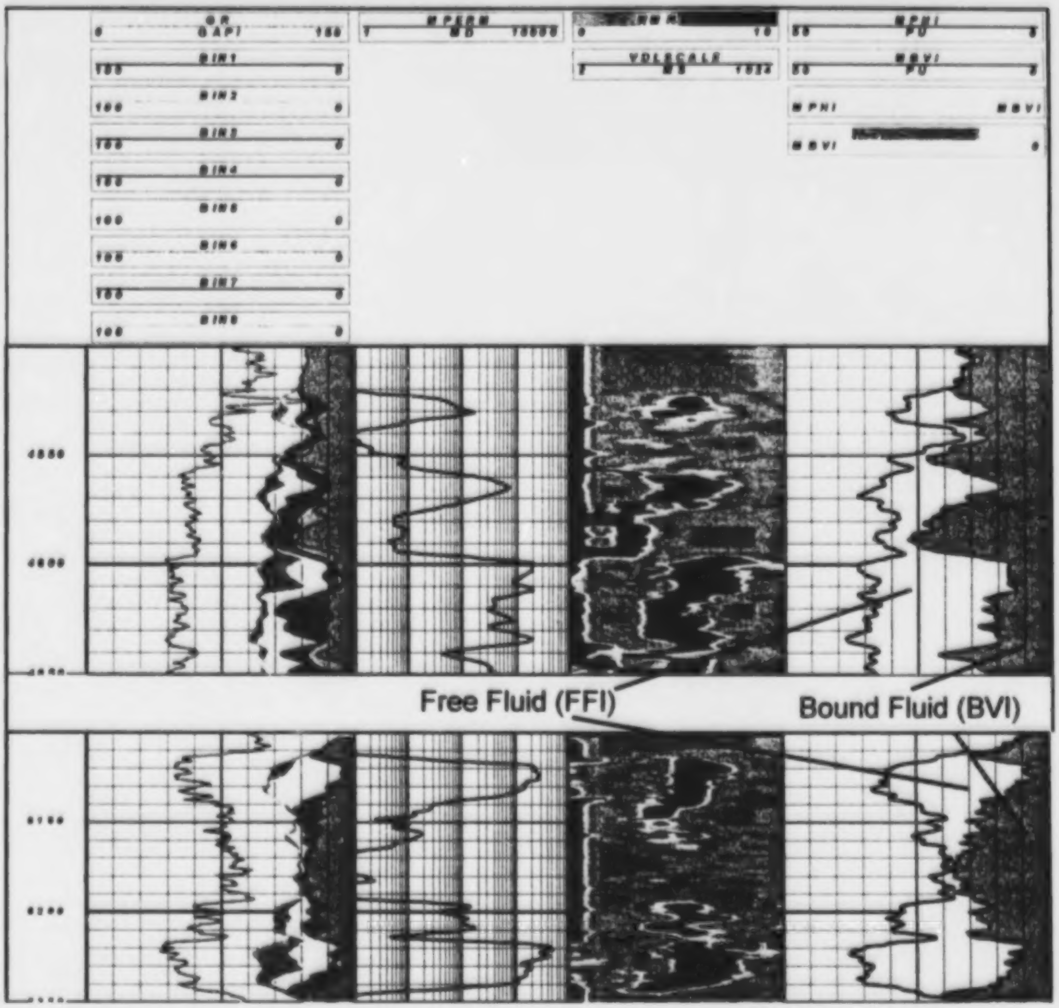
The area in question had a peculiar problem - too much oil production. The reservoir has out-performed its initial estimated potential by 2 ½ times. The question was, where was the oil coming from? There are some pay zones that are fairly obvious on the resistivity logs - upwards of 20 ohm-m. Also there is an obvious water zone with resistivity of 0.25 ohm-m. What about the zones at 1-2 ohm-m? Wet?

NMR Computed Log



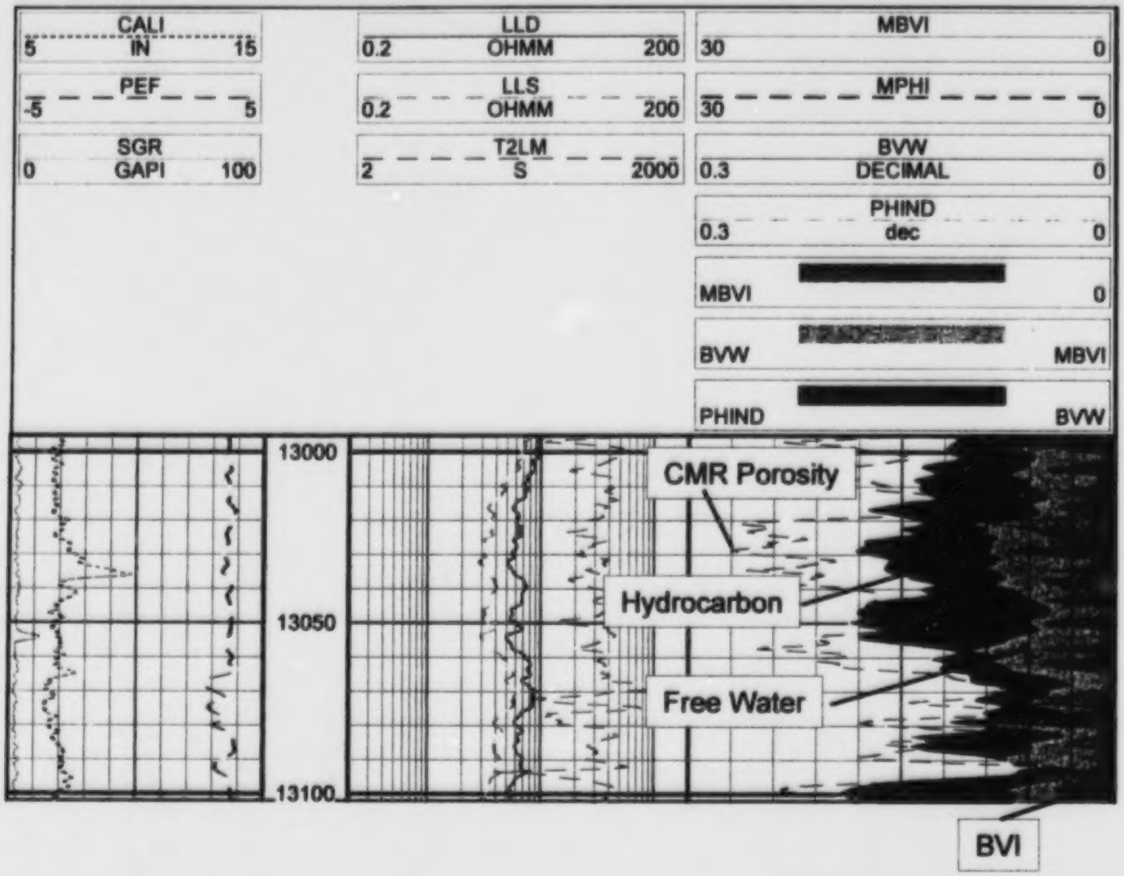
The NMR computed log is shown above. The free fluid volume on the field log is now differentiated as water and hydrocarbon via resistivity analysis. It is also possible to provide water vs. hydrocarbon differentiation (flushed zone) using some of the NMR direct hydrocarbon techniques but that data was not acquired in this well. The MBVI curve provides the needed answers. All of the lower resistivity zones except the 100% water zone are at irreducible conditions. The bulk volume water curve (computed from resistivity) has a very close match to MBVI. Also of interest is the evidence of the oil-water contact on the T2 distribution which causes an apparent shift on the VDL display. The NMR log explains where some of the additional produced volume may have come from, in this case from low resistivity shaley sands having a higher BVI.

NMR Field Log



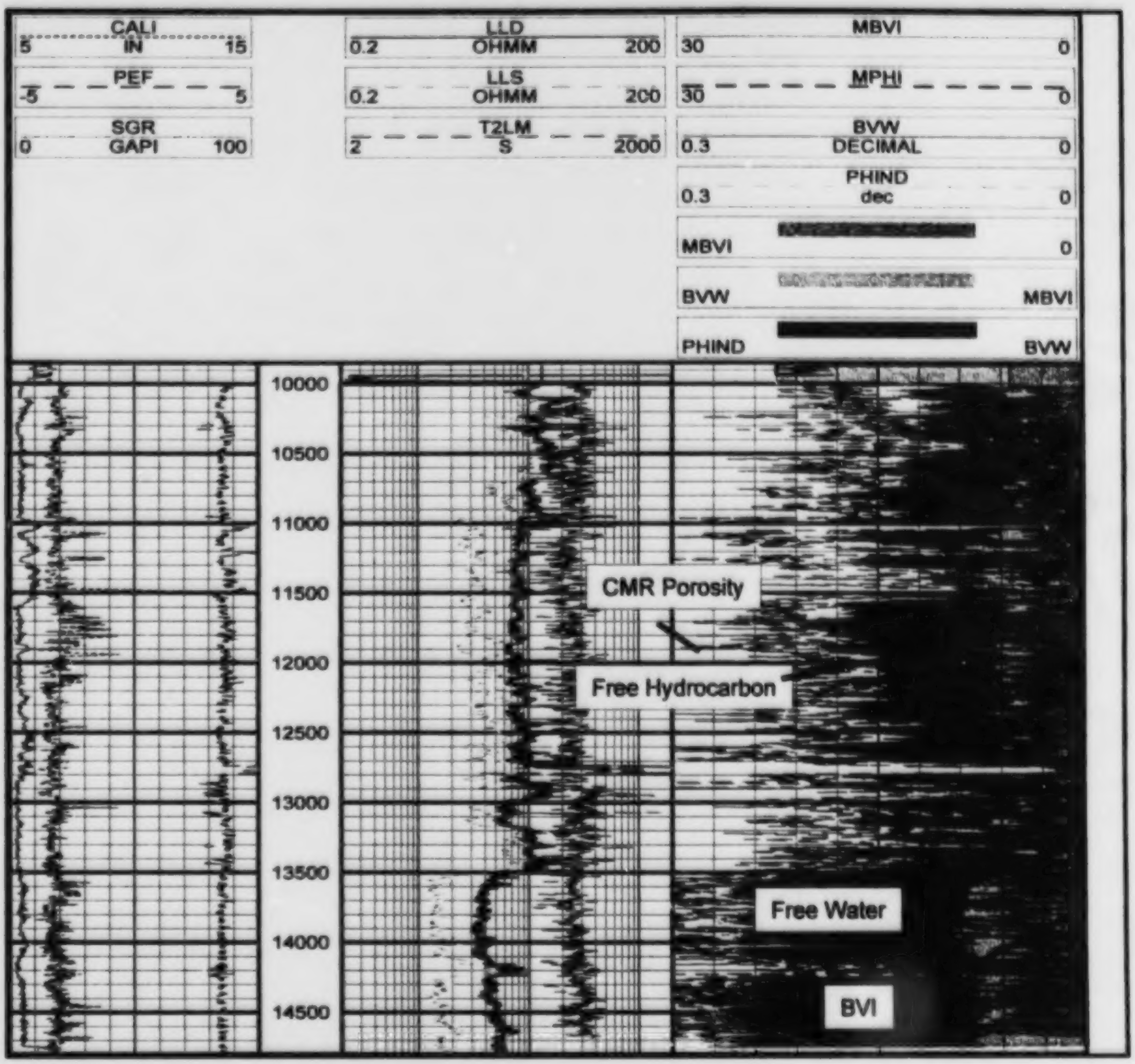
The NMR field log data is displayed above. The T2 porosity bins are displayed in track one. The smaller pores associated with shale and clay are represented by the first few bins on the right. The sands with larger pores are represented by the lighter colored bins on the left. Perm is shown in track two. A VDL display of the T2 data is in the third track. Lower amplitude is light colored, higher amplitudes are darker. The T2 scale is 2 - 512 ms from left to right. This could be considered a rough representation of pore size (shale on the left, large pores right), but it must be remembered that fluids type also shifts the T2. This data is sometimes represented as a wave or wiggle trace on NMR logs. In the fourth track, the top of the light shading is the NMR porosity, the light colored volume is free fluid and the dark is bound fluid.

Horizontal Red River NMR (Detail)



The CMR porosity (dashed) is reading a bit high to the neutron-density crossplot (phind, top of dark shading) indicating some type of problem with the CMR or nuclear log data. Part of the problem may be poor pad contact due to rough borehole. The caliper excursions seen at 13035 is likely to cause the CMR to lose pad contact. This example demonstrates that it is possible to record NMR in horizontal wells.

Horizontal Red River NMR Example (Expanded Scale)



This is an NMR (CMR) computed log example from a horizontal Red River test in North Dakota. In spite of good drilling shows, the well tested wet. The computed log shows some movable water (light colored shading). It has been proposed that the Red River formation may have a pore size or textural change within the zone - perhaps finer grained at the bottom. This may result in lower resistivity readings at the bottom. If so, then NMR logs may identify this textural change and help with resistivity interpretation. In this well, however, the ratio of BVI to porosity and mean T2 (T2LM) are fairly constant. Resistivity is (or actually Rwa) is also fairly constant indicating that the finer grain rock has not been penetrated or is not seen by the logs. The T2 VDL or bin data was not available.

Considerations for NMR Logging in Horizontal Wells

In considering the use of NMR in any well, there should be an assessment of what type of data is to be gathered. Among the types of available data, there are:

- Estimates of total and effective porosity (may be affected by light hydrocarbons but will be free of lithology effects).
- Estimates of BVI – useful for resistivity analysis in varying rock textures, should be calibrated with core data if possible.
- Estimates of permeability – should be calibrated to core is possible.
- Estimates of pore size distributions.
- Flushed zone fluid identification independent of resistivity – particularly useful where resistivity analysis presents difficulties due to varying Rw, varying m and n or where shaliness masks triple combo response.

Consideration should be made of whether the above can be determined from other logs. For example, if it is difficult to obtain neutron-density porosity due to hole rugosity, then the MRIL may provide an alternative and may preclude running neutron density. After determination of needed applications, then it is time to consider operational issues.

Borehole Rugosity

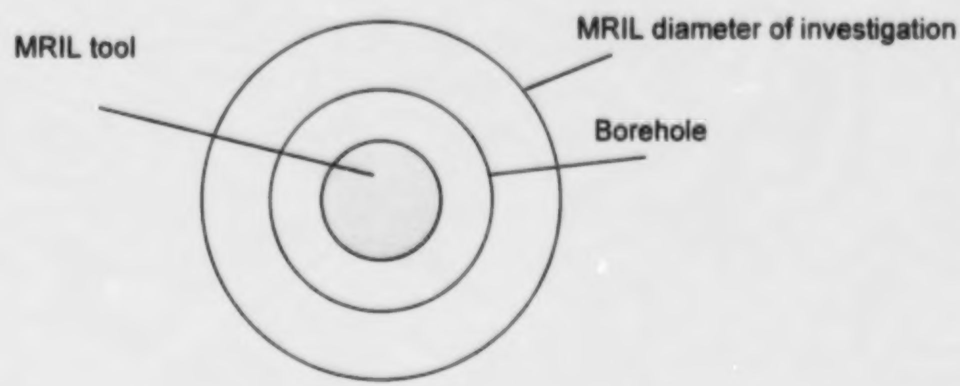
For a horizontal well, if the borehole were likely to be rough as in the Red River example, the MRIL would be recommended.

Borehole Geometry and Centralization

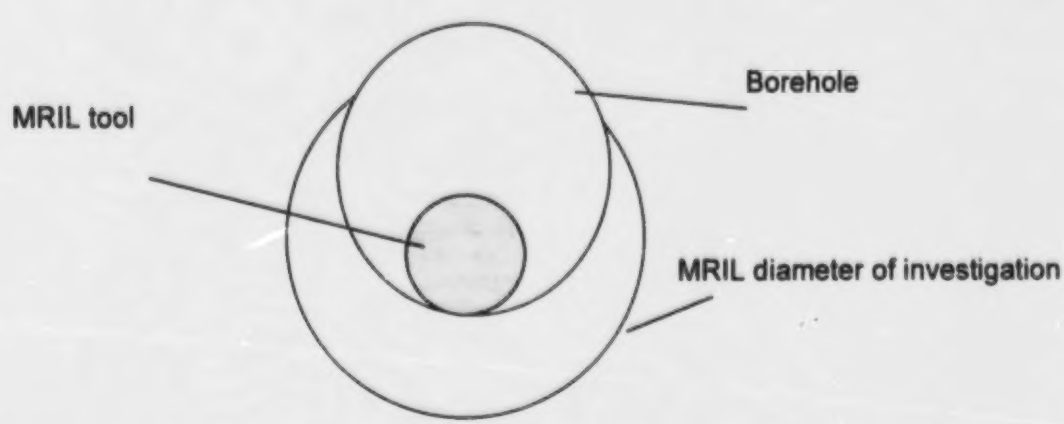
For the MRIL, an estimate must be made of borehole geometry and this should be compared to the expected diameter of investigation of the MRIL. The following table shows the MRIL diameter of investigation for low and high frequency C tools, 4.5" and 6" probes at room temperature and at high BHT. The D (Prime) tool is not listed although it will operate in a band between the low and high frequency tools. Subtract 1-2 inches from the figures below to get a practical upper limit for whole size. Thus, it is not likely to get good data in a 12.25" borehole with a hi freq. 6" tool at 300 Deg F. A low freq. tool should be used.

	4.5" Probe		6" Probe	
Temperature (Deg F)	75	300	75	300
Low freq. (600 kHz)	**12.8"**	**11.1"**	**18"**	**15.5"**
Hi freq. (750 kHz)	**11.2"**	**9.7"**	**15.7"**	**13.5**

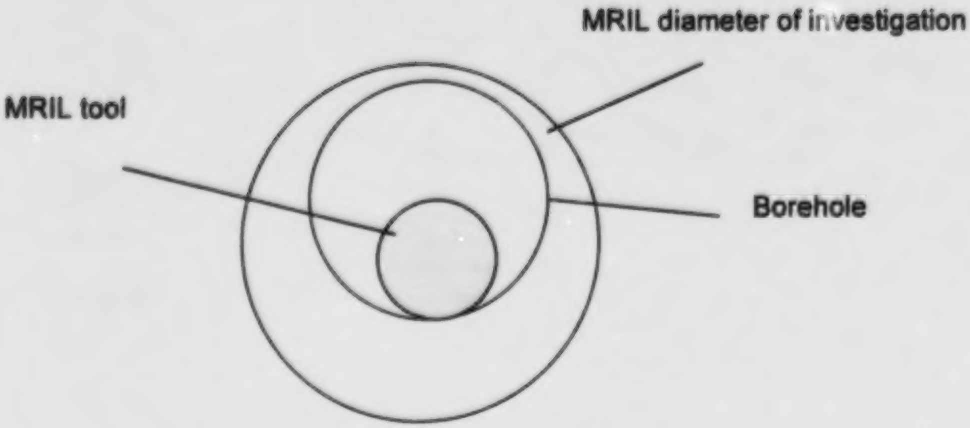
Once a determination of diameter of investigation has been made, this should be compared to the expected borehole geometry. If the borehole diameter exceeds the diameter of investigation at any point, then an erroneously high porosity will be observed. If this were the case, then CMR would be the only option. The CMR is oftentimes easier to manage in a horizontal well. If the CMR skid can be kept face down, then maximum pad contact is maintained since the whole weight of the tool is bearing down on the skid. The diagrams below illustrate the issue of borehole geometry and centralization for the MRIL.



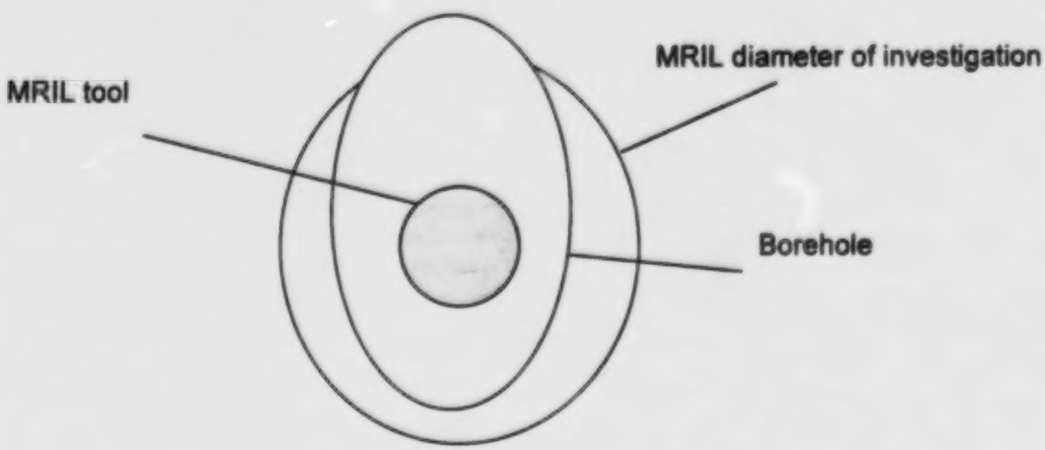
Case #1: MRIL perfectly centralized, round borehole, no problem.



Case #2: MRIL not well centralized, round borehole, hole signal (high porosity) observed.



Case #3: MRIL not well centralized, round borehole, but diameter of investigation is large enough such that it does not intersect the borehole. No borehole signal observed.



Case #4: MRIL well centralized, oblong borehole, borehole signal is observed.

From the above diagrams it can be seen that the borehole geometry and centralization must be carefully considered with the MRIL. MRIL Centralization hardware includes sonic type centralizers for vertical wells, and various types of standoffs for horizontal or high deviation wells. In case #3 above, it is observed that the MRIL can be run successfully without centralization in certain instances. For the CMR it is just a matter of keeping the skid facing down. Wireline "tool turners" that aid in flipping a tool string to achieve the proper orientation can aid this.

NMR Strategy in Saline Muds

The MRIL signal strength suffers in saline muds due to the dissipation of RF energy in the mud column. In order to maintain a signal to noise level that will guarantee repeatability of one p.u. for porosity, the logging speed must be greatly reduced. This effect can be partially offset by using a fiberglass sleeve called a fluid excluder on the sonde. The fluid excluder makes the sonde larger, thus excluding part of the power-robbing salt mud from the region nearest the antenna. This enables a faster logging speed. Sodium resonance is another issue in muds with sodium chloride. Sodium has a resonant frequency much higher than that of hydrogen. Unfortunately, it is of a particular resonance that results in a sodium sensitive diameter that is about half that of hydrogen. If this diameter is in the borehole, a sodium signal of 2.4 p.u per 100kppm sodium will be seen by the MRIL. The sodium resonance will be at about 7-9 inches for the large sonde depending on temperature and frequency. The exact sodium resonance diameter can be determined from the Baker Atlas job planning spreadsheet. In holes of large enough diameter to use the large fluid excluder, the sodium resonance is inside the excluder and the problem is eliminated. However, in areas like West Texas where 7 7/8 or 8.5 are the normal bit size, the large fluid excluder would not fit and the sodium resonance creates a major problem. The solutions;

1) Software correction – clumsy and inaccurate
2) Spot a fresh mud pill – the best for data quality but costs money

The CMR does not suffer from these issues since it is against the borehole wall.

Type of Acquisition;

The CMR and MRIL can be run in "bound fluid" mode acquisition. This mode uses a very short wait time and is meant to only acquire bound fluid data. Free fluid volume would then be estimated by comparison with other porosity sources such as neutron-density. (It has been observed that in some tight gas sands drilled with water-based mud, bound fluid logging can actually pick up all or most of the porosity.) Of course, if the NMR were the only porosity tool being run, this would not be the mode to use. A general recommendation is to record with the longest wait time and to record the greatest number of echoes possible permissible as per the available logging time. Longer wait times allow acquisition of more of the late components of the T2 spectrum which may be useful in characterizing porosity types or fluids with long T2 such as light oil. Another option with the MRIL is to use two wait times (such as one and eight seconds). Attempts at direct fluid typing will have specific requirements for wait time and other parameters.

Tool Combinability

Although there are still some combinability issues, NMR tools can usually be combined with triple combo and many other tools. It is possible to include an MRIL in a Schlumberger tool string with a switching sub. The MRIL has tension, compression and torque limits as described on page 10. It is advisable to work with the local NMR "product champion" to plan for these issues well in advance of the actual logging job.

References;

1. CMR Users Guide, Schlumberger publication

2. NMR Job Planning, Data Acquisition, and Interpretation Workshop, course manual, NMR Petrophysics, Inc.

Biographical Sketch;

Brian Stambaugh is President of NMR Petrophysics, Inc., a petrophysical consultancy based in Houston, Texas. After nine years with Schlumberger, Brian joined Numar Corporation in 1990. While at Numar, Brian assisted with development of new computational techniques specific to NMR data, and assisted with marketing and engineering efforts as borehole NMR technology emerged. He also served as technical and marketing consultant to Computalog, Atlas Wireline and Halliburton Logging Services, and provided interpretation and technical support during assignments in Canada and Indonesia. Brian has performed or supervised the petrophysical analysis of NMR data sets from over 1500 wells. As an independent consultant, he teaches seminars on NMR operations/interpretation, and provides technical assistance on NMR to wireline and oil and gas companies. Brian holds a B. S. M. E. from South Dakota School of Mines and Technology.

Mini Turbine Power Generation from Flare Gas

Williston Basin Horizontal Well Workshop

Bob Williams

Mercury Electric Corporation

Mercury Electric Corporation

Small scale energy solutions

Outline

- Solution gas flaring
- What are mini turbines
- Mini turbine opportunities with flare gas
- The Suncor Joffre Gas Plant Experience
- The PanCanadian Experience
- Test Plans for Williston Basin

What is Solution Gas Flaring?

- Small gas volumes
- Uneconomic to gather & process
- Usually at single wells or batteries

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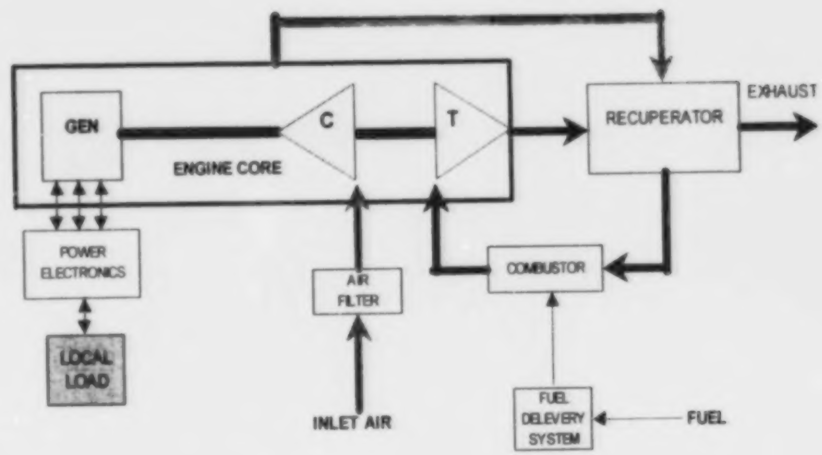
What are Mini Turbines?

- Small gas turbine <100kw
- High speed single shaft design 65,000 + rpm
- Inherently synchronous 60 hz output with power electronics

TurboGenerator™ Power Systems



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What are Mini Turbines?

- Plug'n'Play design
- Everything in one box
- Quiet and low vibration
- Remote monitoring & operation

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Small scale energy solutions

The TurboGenerator™ Power System from AlliedSignal

- 75 kW output
- 30% efficiency
- 3 phase - 208/480/600V
- 65 dba @ 10 metres
- ~4' W x 8' L x 8' H
- 2500 - 3000 lbs
- $1000/kW installed

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Mini Turbine Opportunities with Solution Gas Flares

- Maximizes flexibility by matching number of mini turbines to flare gas volume
- Turns wasted resource into energy
- Reduces routine flaring and replaces generation from other sources

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Mini Turbine Opportunities
Solution Gas Flares

- Reduces greenhouse gas and VOC emissions
- Reliable power in remote locations

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Mercury Electric Case Study

Alpha TurboGenerator™
Demonstration at Suncor Energy Inc.
Joffre Gas Plant April - Sept 1998

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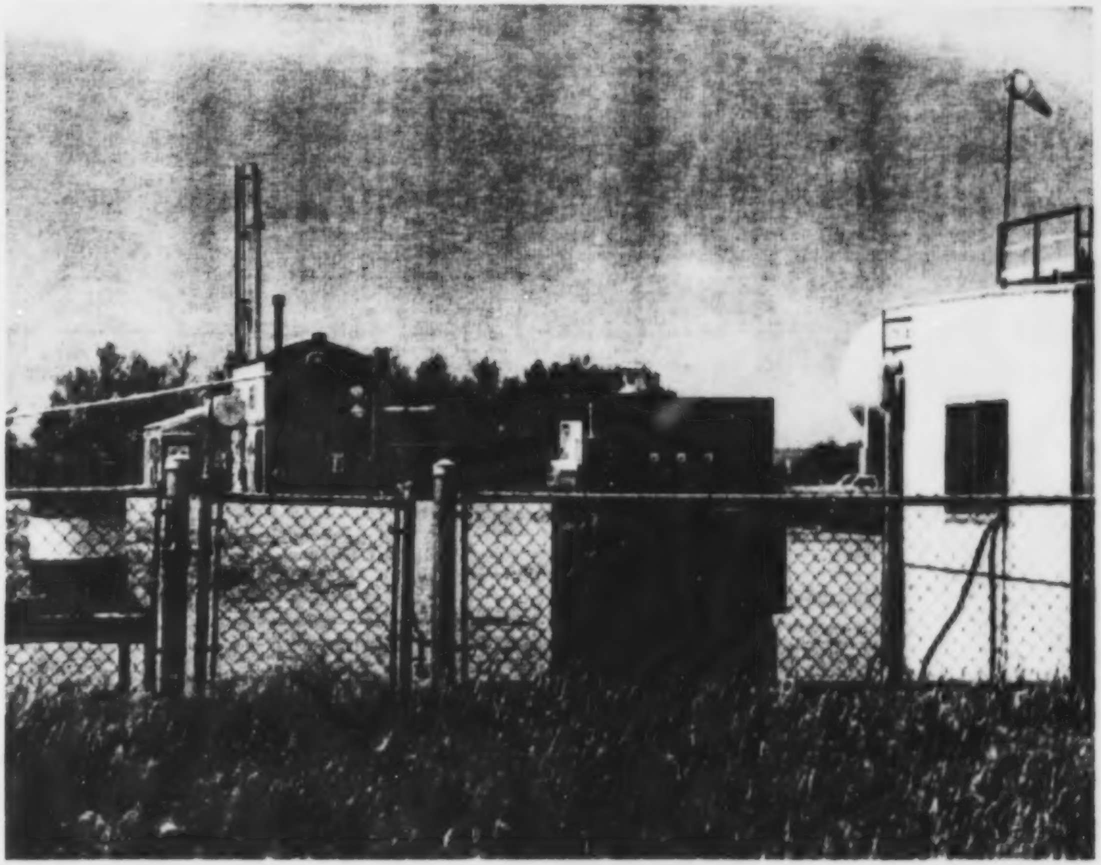
The Suncor Joffre Gas Plant



- View of site from east with Alpha TurboGenerator™ in the foreground

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Suncor Alpha Prototype Test

- 6 month test September - April, 1998
- 37 kW Alpha Prototype TurboGenerator™
- Initially used processed gas at plant outlet
- After 1 month changed to inlet of plant
  - Raw gas composition 80% methane, 9% ethane, 4% propane, 2.0% C_4+, 2.5% CO_2

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Test Results

- Ran flawlessly on raw gas
- Appr. 2400 hours logged
- 42,850 kWh of electricity produced
- 867 MSCF gas consumed
- Alpha efficiency 19.2% vs. target of 21% (production unit will be 30%)

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Test Results

- Only mechanical failure was cracked igniter cable - one hour replacement
- resonance/harmonics shutdowns at high power - filtering solution implemented
- Software modification made to correct non-operational related shutdowns

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Alpha Emissions Performance

- NOx 119.4 ppm vs. 100ppm target (production unit <25 ppm)
- Hydrocarbon destruction > 99.5%
  - Little or no bi-products of partial combustion
- Environmental Implications
  - 50% reduction in Greenhouse Gas Emissions

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Lessons Learned

- Liquids removal essential for long term turbine life
- Depending on level of saturation - up to three steps to filter out liquids
  - 1. Oil battery inlet separator
  - 2. Scrubber
  - 3. Coalescing filter

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PanCanadian Alpha Tests

- Solution gas test @ PanCanadian Duchess Pad
  - Two week test in August, 1998
- Sour gas test @ PanCanadian Wayne Satellite Battery
  - Three week test in February, 1999

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Test Results & Lessons Learned

- Unit ran flawlessly on both sweet & sour solution gas
- Fuel delivery from well to turbine not always straight forward due to:
  - low pressure, volume changes
  - winter freezing if H_2O saturated

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Small scale energy solutions

Test Plans for Williston Basin

- 75 kW Beta TurboGenerator™
- Anderson Exploration
  - Gainsborough battery
  - 1.6% H_2S

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Key Benefits of Mini Turbine Flare Gas Power Generation

- Reduces or eliminates routine flaring
- Completely combusts the fuel
- Reduces greenhouse gas emissions
- Provides economic, reliable power

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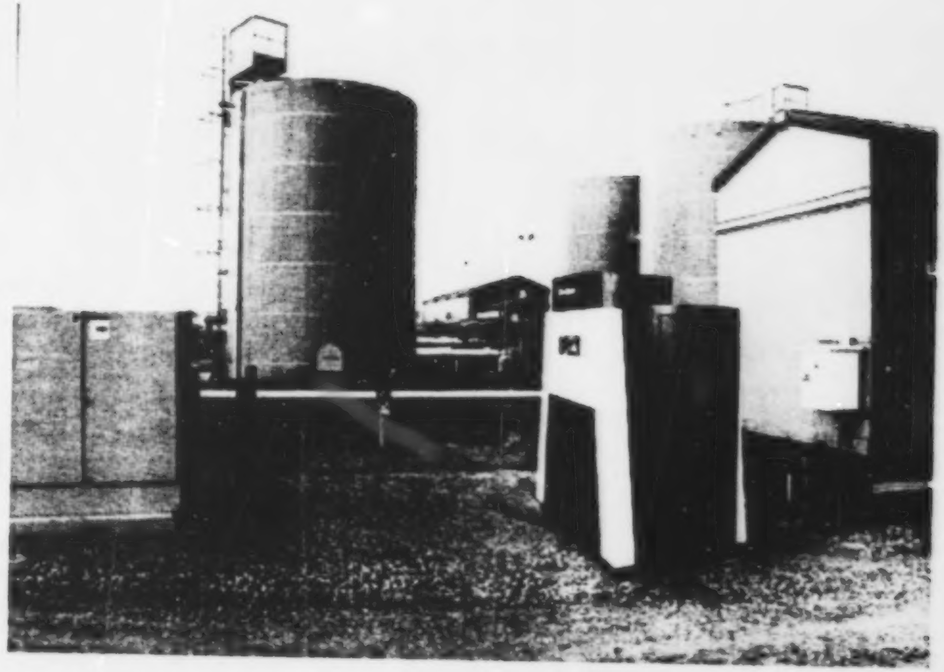
Flare Gas Power - Key Business for Mercury

- Independent Power Producer
- Exclusive distributor TurboGenerator™
  - in Canada
  - 26 countries in Central & South America & Caribbean



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Determination of the Potential for Microbiological Plugging in Saskatchewan Oil Wells, a Case Study.

Cullimore, D.R.[1], Monea, M.[2], Johnston, L.[1], and Keevill, B.[1]

[1] Droycon Bioconcepts Inc., [2] Nautilus Exploration & Associates Ltd.

Abstract

Oil wells in the Kindersley area operated by Nautilus & Associates have been suffering from declining productions which was found to be at least partially caused by build up of solid paraffins and anthracenes (P/A) within the wells. The most obvious effect of this P/A build was that the rods became coated with a black gel-like mass which reduced the efficiency of the oil pumping operations. The traditional remedy for this fouling was the application of hot oil or condensate on a periodic basis to remove the P/A deposits. A microbiological laboratory scale investigation was undertaken on samples from three wells and microbial detritus was discovered in the P/A. This would suggest that the potential exists for the P/A to actually have been bioaccumulated at those plugging sites. Further support for the hypothesis that the P/A accumulation was biologically driven was that the P/A could be removed by the application of a surfactant (CB4, ARCC Inc., FL) and heat. The P/A returned to a fluid state and floated to the surface of the treatment solution and microbial debris of various types was found to float up more slowly than the P/A and accumulated on the underside of the P/A layer. Structures recovered included sheaths (tube-like), threads, ribbons, globular process, crystalized sheets and columnar structures.

Further investigations revealed that the CB4 acted as an effective surfacant lowering the temperature at which the P/A was removed from the rods by 10 to 15°C to 58 to 62°C. Laboratory trials revealed that the P/A was laced with elements associated with microbial growth including sheaths, fibrous EPS and coccoid growth forms and that these structures were compromised by the application of CB4 paralleling the use of CB4 in the rehabilitation of water wells. Evidence would therefore strongly suggest that at least a part of the losses in production in oil wells was associable with microbial plugging that may be a normal part of the production cycle for these oil wells. Wells recently placed in production are being monitored to determine the background levels of aggressivity using the biological activity reaction tests (BART™ , Droycon Bioconcepts Inc., Regina).

Introduction

Little is known of the potential microbial interactions with paraffin formation, crystallization and water flooding associated with oil wells. Theoretical considerations need to be applied since it has generally been considered that oil wells do not suffer from significant microbial interventions beyond corrosion. While attempts have been made to manipulate plugging and degradative processes

using "laboratory-selected" strains of micro-organisms, little attempts have been directed to determine the role of intrinsic microbes in the natural events associated with an oil or gas well. This lack of attention is driven by a mixture of false assumptions (eg, there are no microorganisms in and around oil or gas wells) and conclusions (e.g., the environments are too extreme to allow microorganisms to function). Scientific literature therefore does not contain copious studies on the natural microflora or their potential impacts on the operation of oil and gas wells. Two causes of concern to oil production wells that are of direct interest to Nautilus Exploration & Associates Ltd.. and other oil companies and may reflect a microbially driven event are: (1) the generation of paraffin-like compounds which accumulate around the well and reduce the production capacity; and (2) the competition between water and oil for entry into the well in which the water predominates (causing water flooding). The potential for microbial events to play critical roles in these events will be described and possible management strategies outlined..

Some oil wells suffer from losses in production. One of the causes is related to the plugging accumulation of paraffin-like material around the well. This material is described as a solid grey material tightly formed into cakes in which darker "organic" materials can be seen. These materials gradually accumulate causing losses in production. Standard countermeasures include: (1) high rate fracturing; (2) using larger casings and perforations; (3) incorporating short laterals; (4) applying a solvent extraction to remove the paraffins; (5) use of acidization employing either HCl, HF or HNO_3; and (6) wetting agents.

Some of the wells that have this P/A-plugging problem are in the Viking oil field (near Kindersley). Here, there are 110 afflicted oil wells in a sandstone formation. The wells have an average depth of 750 meters and are producing at a primary of 2 to 4% (2.5 barrels). Five of the wells have a higher "skin" damage. It is thought that most of the paraffin (and some asphaltenes) deposits collect within 50 cms of the well. These deposits take the form of a "wax-like" material in which organic materials appear to be embedded. Gradually the paraffin-rich deposits plug the well off leading to a falling production. Rehabilitation traditionally in the Kindersley area has involved the use of acids, and/or emulsifiers to disrupt the deposits followed by some form of mechanical sheering to remove the deposits.

One potential technology[1] is based around the blended chemical heat treatment (BCHT™) patented process. This treatment functions through the development of a three-phased system in which the targeted regions are subjected to a sequence of shock, disrupt and disperse as a means of removing bio-plugs from a water well and improving the specific capacity[2]. To this date, some 3,200 water wells have been treated in the U.S. with more than 90% returning to greater than 75% of the original specific capacity. Many of these treatments have been performed at the request of the U.S. Army Corp of Engineers (Vicksberg district). The main approach has been focussed on the removal

of the biologically driven plugging with a treatment involving a sequenced application of heat, disinfectants, wetting agents, acids coupled with various methods of mechanical surging. Heat is usually at a level which will elevate column temperatures by >40°C and penetrate into the formations by between 2 and 10 meters (temperature going up in this zone by at least 20°C). The most effective wetting agent used is CB4 (ARCC Inc., Florida) which has been found to disrupt biologically initiated plugging and allowing easier dispersion, along with the shrinkage of some of the clays. Acids commonly double as both disinfectants and hydrolytic agents to reduce the microbial loading and break-up the plugs. If the paraffin-like materials are subjected to these combined effects (heat, acid hydrolysis, dispersion) then it may be expected that there would be some level of melting and migration of the paraffins. This "de-structuring" of the paraffins (P/A) may also be aided by the physical penetration of the BCHT™ treatment in a manner similar to that occurs in the plugging water wells. The major challenge would be the removal of the dispersing P/A released by the treatment. In the present practices, the CB4 wetting agent has been found to be very efficient at reducing particle sizes into the low micron range that enhances the removal potential.

The main objectives of this study related to: (1) the potential role of micro-organisms in the construction of the paraffin-like clogs; (2) suitability of BCHT™ (or some modification of that technology) to disperse the paraffin-like structures; (3) the most effective manner for removing the dispersed materials from the treated well; (4) potential environmental concerns; and (5) the impact on production capacity.

In the water flooding problems in oil wells, there is probably an direct and active competition between water and oil for entry through the perforations into the producing well. Where the entry is dominated by water, these wells are considered to be affected by "water flooding" and the product would contain an inordinately high (unacceptable) water content. These events can occur where there are restricted formation thicknesses in the active zones with the water and oil competing for entry, or there may be a bottom water generating upward pressure causing water entry into the well (active bottom water). The remedy is to block off the water from entry into the well. This process is called "water blocking" and can significantly improve oil recovery from a well affected by a water flood.

A new Ukrainian technique for water blocking involves the treatment of the well with a slurry of wetting agents, bentonite, hematite, and magnetite. To establish the block, an electrical (EMF) circuit is created across the region where the water block is to be formed. Blockage is evident within two hours of successful application. When this technique was applied to some Ukrainian and Russian oil wells, the percentage decrease in water being pumped with the oil ranged (well to well) from 87%, 93%, 100%, 75%, 64%, 68%, 11%, 84%, 100%, 81%, 100% and 100% for the wells included in the test series. The functioning of the EMF induced water block (barrier) remains unclear. In the field, the establishment of the block appeared to occur within two hours and was

durable. A contribution to the understanding of the functioning of this technology could be made through enhancing the knowledge of the potential manners in which microbes may contribute to the processes of forming the barrier. The observations below are based upon experiential evidences working with plugging laboratory mesocosms and producing water wells.

Major components that may be subject to microbial influences leading to a plugging condition (desirable in a water-blocking scenario) could be: (1) magnetite and hematite, both products of microbial activity and high in iron (receptive to EMF effects and it is probable that these materials would form a focus for the activities by iron related bacteria); (2) surfactants would act as wetting agents through opening up the pore structures in the clays, hematite and magnetite allowing greater microbial colonization with the bioconcretious formation of plug-like slimes; (3) the application of an EMF to the treated formation is likely to re-orient the magnetite and hematite into developing charged fields within which the microbes may concentrate (probably around the anodic regions); and (4) clays would form extensive charged surfaces over which the microbes would attach, generate slimes and cause secondary accumulations of the hematite and magnetite.

Once the microbial activity has become focused through the coupled application of EMF, surfactants, clays and minerals, the subsequent slime growths would generate a hardening form of clog that would have reduced water permeability. In the generation of the water block (barrier), there is an advantage in understanding the management factors that could be used to further stimulate the intrinsic microbial activity.

Of most direct concern in this study is: (1) a validation that microorganisms are involved in the accumulation of the paraffins and anthracenes; and (2) theoretical and application phase in which a paraffin-plugged well would be treated.

Laboratory Studies I, (CB4 treatment in combination with heat)

The first phase was to conduct laboratory assessments of potential methodologies for the removal of paraffin/anthrocene (P/A) plugging from compromised oil wells and recommend appropriate treatment procedures for field scale testing. This project was designed to determine the ability of the wetting agent in conjunction with heat (in the form of hot water or oil) to remove accumulations of paraffin and anthracene (P/A) within oil wells and distribution lines. Given that this evaluation is reactive to the events as they unfold, a greater level of effort was initially placed on the removal of P/A from the 2" steel distribution lines where severe P/A clogging was occurring. This was followed by studies using P/A plugged rods.

Using straight water as the control with 1% P/A as a black conglomerate mass in 500 ml of water, the effect of heat with various concentration of CB4 was evaluated. In summary, the CB4 caused a more rapid effect with the raising of the temperature. Generally, the CB4 caused parallel

effects at 5°C lower temperatures than the straight water. Normally, the P/A mass would begin (with the CB-4) to lose structure at 52 to 54°C and become buoyant at 57 to 61°C. By 64 °C, all of the P/A had risen to the surface of the water as an oil slick. As already noted, the straight heated water lagged by at least 5°C in achieving the same mobility and the oil was less fluid. Generally, it was noticed that the P/A in the water hardened quicker (less than 30 minutes) to form a plastic-like crust that had a matt black surface. In the presence of CB4, the P/A remained fluid for longer, developed a light brown sheen and an irregular surface. In addition, the P/A removed using CB-4 was much softer and more flexible in form even when it had cooled.

Concentrations of CB4 were found to influence the rate of P/A fluidization and lifting. For the straight water to P/A concentration interaction, it was found that the most significant fluidization and lifting occurred at lower temperatures with 0.75% to 1.0% CB4 although this was not vastly superior to 0.1% and 2%. It was therefore decided to proceed to examine the effectiveness of CB4 to fluidize and lift P/A conglomerates in sand based porous media at different temperatures with water as the control. At the same time, additional priority was given to the determination of the ability of CB4 to trigger the fluidization and releases of P/A "clogged" conglomerates. For this purpose, Nautilus Exploration & Associates Ltd. provided some sections of 6 month "aged" 2inch steel pipe. This pipe had been totally clogged with P/A material and had been removed from the distribution network. Seven 5" sections and three 16" sections of clogged pipe were supplied for this investigation. The first trial with 1% CB-4 showed a complete fluidization and lifting of the P/A by 62°C which left the pipe clean with no significant loss in diameter or retained internal P/A conglomerates to reduce fluid conductivity. This trial was so significant that it was decided to concentrate on the determination of the controlling parameters for this event. The reasoning behind this was that there appeared to be that a potentially straightforward methodology for the removal of P/A from distribution systems using a 1% (provisional concentration) of CB4 coupled with hot water.

In summary, when compared to straight hot water, the CB4 addition caused the P/A to become more "fluid" commonly forming oil droplets that coalesced easily over the surface of the water. The mobilization of the P/A also was more dynamic in the presence of CB4 than in the straight hot water. The sequence of events in and around the pipe when immersed in the CB4 solution and heated gradually showed the following trends: (1) fluidization began at between 52 and 55°C; (2) early signals were oil droplets forming around the upper end of the pipe and oil oozing out the lower end of the pipe; (3) oil droplets of 2 to 4 mm diameter would begin to cover the surface of the water until a coherent oil film was formed on the surface of the water (at 56 to 59°C); and (4) the outer edge of the P/A at the top and bottom of the pipe became more fluid and oozed out leaving a cavity. It was found at this time that pressing down on the solid central core caused P/A oil to be

pressed out under the pipe and rise up to the surface outside of the pipe. Once all of the P/A had lifted, the pipe could be removed (while the water was still at greater than 65°C) virtually free of P/A beyond a light coating of the surface.

When water was used alone, as with the previous experiments, the P/A did not fluidize until at least 5°C higher and produced a product that hardened quickly and was relatively brittle. It would therefore be reasonable to assert that the CB4 at 1% (although not optimized) did influence the rate of fluidization and lifting of the P/A in a positive manner and generated a more controllable product in that it did not harden so quickly. This technology be applied to a selected short length of P/A clogged pipe under field conditions. Here, it would involve the recycling of heated 1% CB4 through that section of pipe until the internal temperature reached 62 °C whereupon most of the P/A would have become fluidized. In this state, it could easily be surged from the pipe section.

The first trial (Table One) utilized a solution of CB-4 (1% of solution volume) and water was added to a beaker. A 6 inch piece of 2" pipe totally plugged with P/A, was added to the solution. The temperature of the solution was slowly raised until all the P/A had liquefied and flowed out of the pipe. In this experiment, the initial temperature of the solution was 30°C.

Table One

Impact of 1% CB4 Aqueous Solution on P/A Deposits Plugging a 2" Steel Pipe Section when Subjected to Heating (°C).

Temperature of the Solution	Temperature of the P/A	Comments
35 °C	30 °C	No significant change.
55 °C	32 °C	Some P/A flows from the bottom of the pipe and adheres to the outside of the pipe.
57 °C	36 °C	Small pea size balls of P/A come from the bottom of the pipe Some P/A on the side of the pipe is released, is fluidized and is lifted to the surface.
62 °C	50 °C	The P/A is released from pipe and is lifted out as a cylindrical core. Pipe is cleared.

In the control study, water alone was added to the beaker and a 6 inch piece of pipe, plugged with P/A, was added to the solution. The temperature of the solution was slowly raised until all the

P/A had liquefied and flowed out of the pipe (Table Two). The CB4 solution caused a much more rapid mobilization of the P/A with significant flows occurring from the pipe while the external solution temperature was 55°C and the internal P/A was still relatively cool. By the time the internal temperature of the P/A had reached 50°C, the P/A had become mobilized and lifted out of the pipe. The temperature at which this occurred with just the water was 67°C, the 1% CB4 solution had therefore caused a much more rapid fluidization of the P/A.

Table Two

Impact of Water alone on P/A Deposits Plugging a 2" Steel Pipe Section when Subjected to Heating (°C).

Temperature of the Solution	Temperature of the P/A	Comments
27°C	27°C	No significant change
50°C	32°C	No significant change
57°C	36°C	Small glob forms at the base
59°C	38°C	Globs remain
60°C	39°C	Melted P/A begins to flow quickly from the top of the pipe
61°C	40°C	P/A remaining inside the pipe is still thick the P/A that has melted and floated to the top of the solution is forming a hard film.
62°C	58°C	P/A remaining inside the pipe is still thick
63°C	63°C	P/A inside the pipe is softening
65°C	63°C	P/A inside the pipe is free from the pipe walls A thick core of P/A remains loosely in the pipe
67°C	67°C	All P/A has turned to a fluid state and floats on top of the solution. Pipe is cleaned

Evidence to-date supports the possibility that the paraffins and anthracenes are actually being bioaccumulated within, and around the well as a black tar-like "goop". Evidence of biological activity stems from the following repeated events that have been observed. These are:

- There is a rapid gas bubble formation in distinct patterns over the black P/A mass as soon as it is immersed in water. These bubbles form rapidly to a size of between 2 and 4 mm and remain locked to the P/A surfaces. Any biological activity within the P/A would be severely water-stressed since the mass is commonly thought to contain less than 0.1% water. The sudden "flood" of water caused by immersion would cause a rapid intake of some of that water into the biological structures within the P/A. Concurrently with this surfeit of water, there would also be free oxygen in that water. The sudden abundance of oxygen could cause a burst in respiratory activity generating the carbon dioxide which collects as bubbles on the outside of the P/A mass. The sites of the bubbles formation is likely to be at sites where biological conduits interface with the surrounding medium (which would normally be oil)
- There is a rapid swelling of the P/A when the temperature of the water (with CB4 @1%) rises from 35 to 54°C. In experiments with rods coated with P/A, it was common to see the thickness of the P/A coating increase by an average of 50 to 75% with localized eruptive swellings increasing to as much as 150 or 200% of the original thickness. It could be reasonable postulate that water was entering the P/A via biological conduits causing these conduits to swell while the CB4 begins to degrade the polymeric "webbing" which was synthesized by the microorganisms to form habitable structures in which the P/A became relatively passively accumulated.
- As the temperature rises between 55 and 65°C, destabilization now occurs in a radical manner due to the complete disruption of the polymeric "webbing". There is a release of some of the P/A as droplets which are expressed from the black "goop" structures to float upwards to the surface as liquid droplets. As the temperature reaches 65 to 67°C, the hot water in combination with the CB-4 causes a complete collapse of the "goop" and the fractions of P/A revert to a liquid state and float upwards. The collapse of the P/A "goop" can be explained through the massive admission of hot water into a water-starved environment (i.e., the oil) along with the admission of the CB4 which destroyed the biological structures within that "goop".

It should be noted that the hot water without CB4 lags behind, commonly requiring an additional 10 to 15C° to cause mobilization of the P/A. Additionally, the resultant liquefied P/A commonly does not generate typical oil droplets and tends to "harden" quickly. It may be hypothesized that the polymeric structures (destroyed when applying CB4) survives (in the absence of CB4) and causes this hardening which would make the product more difficult to control and remove.

Laboratory Studies II, (Microbiological Aspects)

When the P/A coated rods are treated with hot water and CB4, it is common to see a variety of collapsed structures appearing in the water as the disruption occurs. Many of these structures can be explained as having biological origins. What are more significant, are the events which follow the removal of the P/A from the rods. The P/A rises to the surface of the water where it remains liquid until the temperature drops. Some P/A is observed to sink due to associations with heavier materials such as sands and silts but later this mobilizes again and lifts to join the lower surface of the floating P/A coagulum. While the P/A forms a continuous coagulating film over the surface of the hot water, debris now begins to rise and collect under the formed film of P/A. Within this debris coating on the underside of the P/A are many structures which would appear to have a biological origins. Similar structures have been observed in the biofilms filmed during corrosion experiments using BART™ biodetectors, in bioconcretions such as the rusticles from the RMS Titanic[3], and in plugs recovered from biofouling around water wells. Common elements include: sheathed structures (some resembling *Leptothrix*), threads (mycelial like), woven threads, resinous mats, crystalline plates, as well as both spherical and columnar structures.

There would appear to be a probability the P/A formation in, and around, an oil well could involve microbial activity. This activity would first of all be dependent on the "mining" of water out of the oil through bonding the water in extracellular polymeric structures. These would then provide a basal water matrix within which the microorganisms could now grow. The P/A accumulation may be an incidental byproduct of the interaction with, and accumulation of the fractions of oil in, and around, the biologically active bound water matrix. To test this hypothesis, samples of the oil and P/A were examined for the presence of aggressive bacteria using the biological activity reaction tests (BART™)[4]. A general pattern emerged from the testing both the oil and the P/A. Very aggressive slime forming bacteria (SLYM-BART™) were detected with the test going positive in one day with a CP (cloudy plate) followed by DS (dense slime) which gradually elevated (like a "thunder head" cloud) until the whole test vial went CL (cloudy). Using the SRB-BART™ that is used to detect sulfate reducing bacteria, very aggressive colloidal forming anaerobes were detected in one to two days (CG, cloudy gel). This would also be seen on the first day of testing as a colloidal matrix rich in bubbles that had a very high viscosity (i.e., when the test vial was tilted or rotated, the contents behaved as a single gelatinous mass). By day two, these reactions disappeared and the test now appeared negative for SRB and anaerobic bacteria. This would indicate that the dominant flora were slime-forming bacteria which had not been able to adapt fully to grow in the SRB-BART™ but did generate some initial signals of activity (i.e., gas foaming and gel formation).

Water from beneath the floating P/A plate formed by the heat treatment was found to have

coated the underside of the plate with debris. This appeared to be dominated by a population of sheathed iron related bacteria tentatively classified as *Leptothrix*.

From the above observations, a theoretical structure for the biological activity can be proposed. This would be a structure of interlacing conduits that would interconnect between the various surfaces of the P/A and the internal fibrous, thread-like and sheathed structures sited at various locations within the P/A structure. The limiting nutrient would probably be water with respiratory substrates also restricting. This substrate may be associable with the iron in the well construction (ferrous-ferric shunt) or some other electron acceptor systems. The impact of adding oxygenated hot water to replace the oil fractions in the environment would cause considerable stress in the biological structures resulting in retention failure and the releases of the accumulated P/A.

Conclusions

A body of evidence was observed which leads to the conclusion that some form of microbial biofouling occurs within, and around, an oil well. From these experiments, it would appear that the biofouling is initiated through slime forming bacteria "mining" water from the oil and constructing a series of micro-habitats within the bound water phase. This phase is formed by extracellular polymeric substances into which the P/A accumulates which then, possibly, provides additional protection to the incumbent microorganisms. Application of heat and CB4, as the surfactant, causes the hydrolytic disruption of these polymeric matrices, and collapse of the structures bonding the P/A which now becomes liquified and is released.

When the mass of the P/A ("black goop") is disrupted and released by the impact of t he CB4 and heat, the liquified P/A rapidly floats top the surface. The microbial debris generated by the heat/CB4 treatment rises more slowly and settles on the underside of the floating P/A plate. Using reflectance light microscopy, it is possible to observe the various structures *in situ* that include sheathed structures (some resembling *Leptothrix*), threads (mycelial like), woven threads, resinous mats, crystalline plates, as well as both spherical (globular) and columnar structures.

Given the probability that oil wells have been subjected to this form of biofouling (based upon direct observations of debris, and the activity recorded in the BART™ tests), improved production may be achieved by applying the same principals to oil wells as are presently being applied to water wells to render these installations more sustainable. In the water industry, this is now beginning to be implemented by a combination of practices that are a blend of preventative maintenance and radical treatments generated by routine testing for the specific capacity (as the measure of production) and the bacterial aggressivity (using the BART™ tests). This can be monitored using the well fouling hazard index (WFHI[2]). In the water industry, the recovery of a water well becomes more challenging as the specific capacity falls by 20 to 40% and becomes very

difficult once the well has fallen by more than 60%, that means to less than 40% of it's original specific capacity. The premise now being adopted by that industry is to assume the inevitability of biofouling (plugging) and begin preventative maintenance from the time the well goes into production so that production can be maintained. Present evidence suggests that 70% of all water wells are subjected to major (fatal) levels of bacterial fouling and, in the Canadian prairies[5], the average life span is 15 years. The aim is to double the life span of a producing water well and make it that much more sustainable. From the studies to-date, it would appear probable that oil wells are also subject of this type of biofouling (plugging) and a similar strategy now needs to be developed by the oil industry similar to that already being implemented in the water industry.

Acknowledgements

The authors wish to acknowledge the financial support of the National Research Council - Industrial Research Assistance Program for this project, and the staff of both Nautilus Exploration & Associates Ltd., and Droycon Bioconcepts Inc., for their support in providing P/A samples, CB4, test sites and data.

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Seventh International Williston Basin Horizontal Well Workshop

Coiled Tubing Horizontal Drilling

Bert von Hertzberg

Fracmaster Ltd.

Underbalanced Drilling

Conventional - Overbalanced

- hydrostatic pressure > formation
- no formation inflow

Underbalanced

- hydrostatic pressure < formation
- inflow

Underbalanced Drilling

- Proven technology
- Economic and Tech benefits

Why Drill Underbalanced?

- Reduce formation damage
- Minimize stimulation requirements
- Provide real-time reservoir evaluation
- Reduce drilling problems

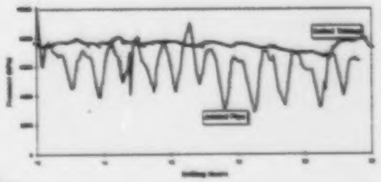
Drilling Problems

- Lost circulation
- Differential Sticking
- Kick Control

Why Coiled Tubing?

- Safe and efficient operation on live wells
- No connections means homogeneous circulation (esp. with multi-phase flow)

Bottom Hole Annular Pressures



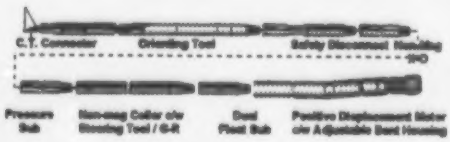
Why Coiled Tubing?

- Safe and efficient operation on live wells
- No connections means homogeneous circulation (esp. with multi-phase flow)
- Wireline telemetry application
- Real-time directional data

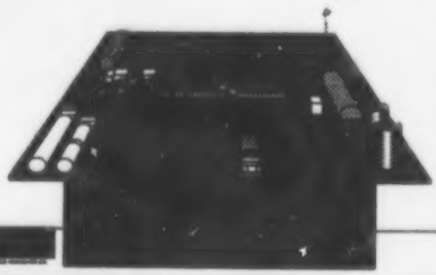
Geosteering

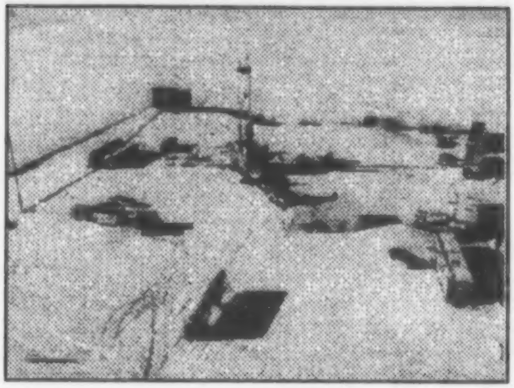
- Real-time gamma ray logging
- Real-time downhole pressure
- Reduced sampling times
- Real-time inflow monitoring

Directional Bottom Hole Assembly



Directional Lease Layout

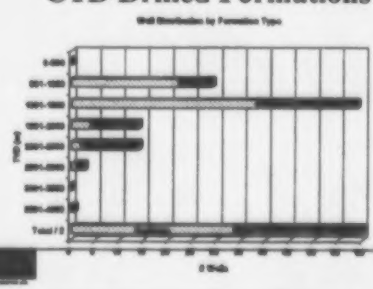




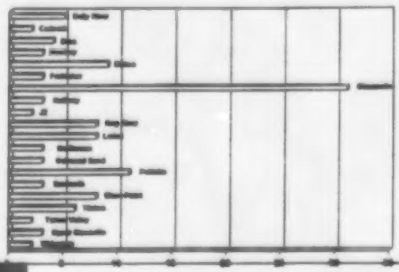
Well Summary

Company Name/Location	Drilling Time (hrs)	# Logs	Total Drilled (m)	TVD (m)	TMD (mKB)	Drilling Fluid	CT Size (mm)	Hole Size (mm)	H_2S %
Vaso 1-3W4	62.0	2	302/712	1205	1582	Oil/N_2	60.3	120.7	1
Ascentax 10-10W2M	68.8	3	311	1196	1196	Oil/N_2	60.3	120.7	2
Summit 6-33W4	29.8	1	307	1287	1610	Oil/N_2	60.3	120.7	1
Sceptre 6-34W4	35.0	1	222	1131	1080	Oil/N_2	60.3	120.7	1
Tight Hole	38.3	1	428	1350	n/a	H_2O/Oil/N_2	30.3	120.7	1
Tight Hole	47.0	1	83	n/a	n/a	Oil/N_2	60.3	120.7	1
Sceptre 8-8W2M	48.3	1	84	1177	1142	Oil/N_2	73.0	120.7	0
Vaso 2-34W4	35.5	1	376	1375	1388	Oil/N_2	73.0	120.7	0
Lateral Vector 6-8W2M	164.2	3	[illegible]	1182	1846	H_2O/Oil/N_2	73.0	120.7	0
Other 6-14W2M	23.3	1	101	1440	2002	Oil/N_2	73.0	155.6	0
Purcell 6-14 W2M	29.3	1	440	1429	1829	Oil/N_2	73.0	120.7	1
Zargon 7-31W4	43.8	1	427	876	1462	Oil/N_2	73.0	120.7	2
Zargon 7-31W4	40.8	1	431	880	1486	Oil/N_2	60.3	98.4	2

CTD Drilled Formations



CTD REPEAT FORMATIONS



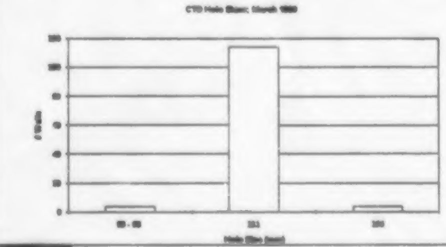
Coiled Tubing Applications March 1999

- Horizontal Extensions (104)
- Multi-laterals / Sidetracks (10)
- Re-entries / Builds (10)

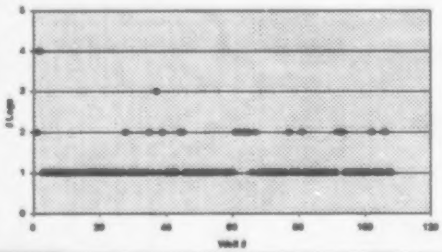
Hole Sizes - March 1999

- 95 - 98 mm out of 114.3 mm (4)
- 120.7 mm out of 139.7mm (112)
- 120.7 mm out of 156.8mm OH (4)
- 155.6 mm out of 177.8mm (4)

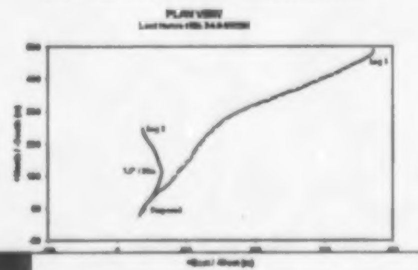
CTD Hole Size Distribution



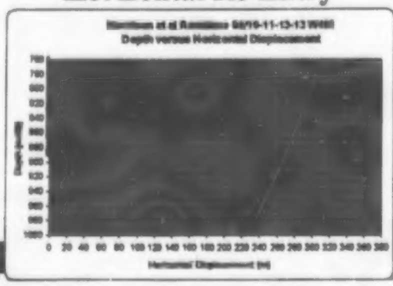
CTD MULTI-LEGS

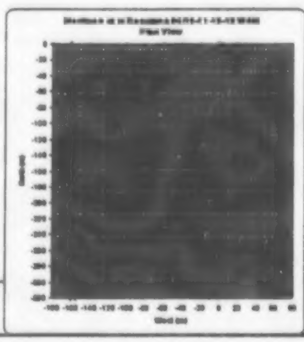


Multi-Lateral Extension

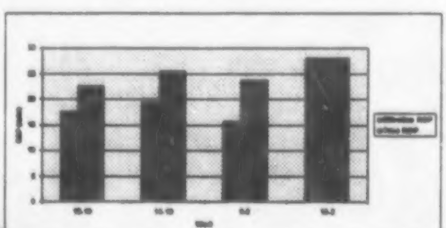


Horizontal Case Studies Horizontal Re-Entry





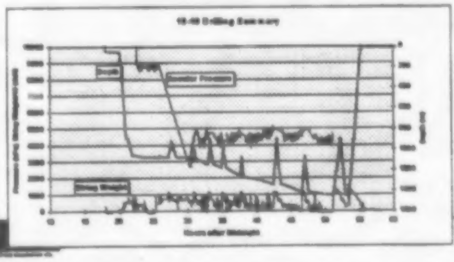
ROP Comparisons



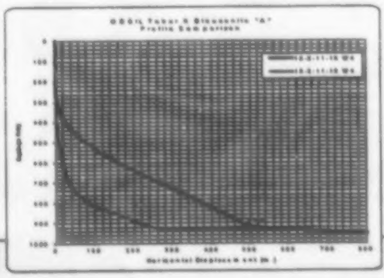
Operational Issues

- Hole Cleaning
- Stuck Pipe
- Wireline Integrity

Drilling Issues: Hole Cleaning



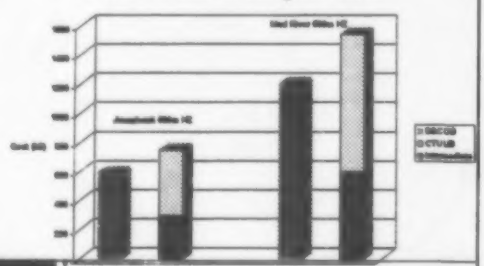
Hole Cleaning - 7" Casings



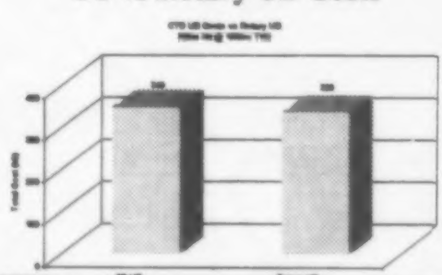
Buckling and Lockup

- CT will buckle
- Sinusoidal buckling
  - not serious
  - minimal drag increase
- Helical Buckling
  - precursor to lockup
  - significant drag increase

CTD Cost Comparison



CT vs Rotary UB Costs



OPERATIONAL IMPROVEMENTS (OPERATOR)

- Rig Up Time
- N_2 Costs / Alternatives
- Downhole Failures
- Pressure Deployment
- Bit Selection
- Stuck Pipe

Rig Up Time

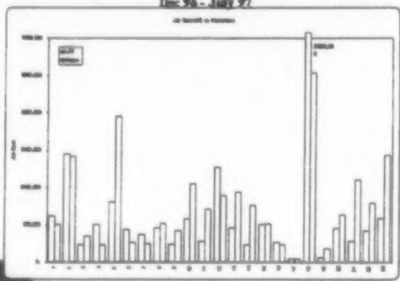
- Currently 18 hours in summer, 24 hours plus in winter
- co-ordination of all services a must
- cannot be significantly reduced on current generation of drilling units
- major consideration in design of next generation

Nitrogen Costs

- Choice of cryogenic or membrane
- dependant on location, availability and expected time on location
- close to N_2 source, short time (3 to 5 days), cryogenic can be cost effective
- remote locations, long time on location, multiple wells, membrane nitrogen can be a viable alternative

Cryogenic N_2 vs. Membrane

Dec 96 - July 97



Downhole Failures

- Early jobs had significant number of downhole tool failures - learning curve
- improvements in coil/wireline management, tool maintenance
- acquired knowledge of limitations
- improved communication with operator

Wireline Integrity

- Braided Cables
- High Fluid Velocities
- Slack Management

High Pressure Deployment

- Currently requires the use of third party wireline and lubricators
- considering redesigning current rigs to be self-sufficient
- generally requires 3 pulls for complete BHA

Bit Selection

- Selection operator decision
- bit records scarce for small sizes
- building a data base in-house but will require time

Stuck Pipe

- no ability to rotate
- hole cleaning crucial - wiper trips
- formation stability - job planning
- options include fluid/N_2 hammer
- parasite string
- shear disconnect
- hydraulic disconnect

Case Study - Oil

Jenner Upper Mannville OO Pool

- 75% Quartz / 25% Chert Sand
- Poorly to Unconsolidated
- 25% Porosity
- > 1 Darcy Permeability
- Gas Cap and Water Contact
- Pressure ~ 9000 kPa
- Water Typical After ~ 6 Months

Majorville Upper Mannville B Pool

- 23% Average Porosity
- 0.5 - 1.0 Darcy Permeability
- Areas Overlain by Thin Gas Sand
- No Water
- 9000 - 10,000 kPa Pressure
- 7500 kPa Anticipated at Locations

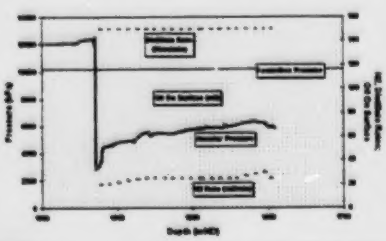
Jenner 16-14
Mannville OO Pool

- Program Similar to 15-14
- Drilled 336 m in ~ 32 Hours
- ROP_{avg} ~ 10.5 m/hr with 7 Wiper Trips
- P_{ann} ~ 4500 kPa
- 1.5 - 2.5 m^3/hr Oil Inflow
- 26 Hours Rig Repair

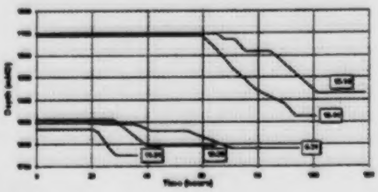
Majorville 10-30
Upper Mannville B Pool

- 75-200 m Horizontal UB Wellbore
- Native Crude / N_2 @ 0.20/30 m3/min
- 120 m in 13.5 hours
- ROP_{avg} ~ 8.9 m/hr with Wiper Trips
- P_{ann} of 3700 to 5400 kPa
- Oil Inflow Up to 13 m^3/hr (88 m^3 Total)

11-31 Drilling Data



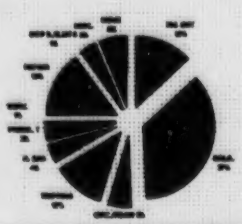
Drilling Plan Summary



Drilling Summary

- Rotary Drilling - 139.7mm Casing to 90°
- 10-15° / 30m Build Rates
- Service Rig - Float Collar to Shoe

Operational Analysis



Reservoir Productivity

Costs - SE Alberta Oil Wells

Conclusions

- Objectives Were Met Using CT UB
- Majorville Wells Appear Good Candidates
- Jenner Wells Need Further Evaluation

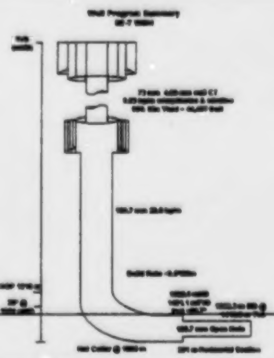
CASE STUDY

Montney / Belloy Formations

82 - 7 W6M

82-7 W6M Case Study
Montney / Belloy Formations

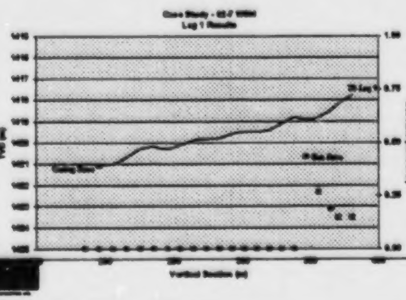
- **Primary Target = Basal Montney Sand**
- **Diesel / N2 Drilling Fluids**
- **Flow Tests Planned**
- **Secondary Target = Belloy Sand**



82-7 W6M Case Study
Leg 1 Results

- Drilled 1532 - 1726mMD
- Pann ~ 6500 - 8000 kPa
- Diesel / N2 @ 0.45 / 15 m3/min
- ROP ~ 7 m/hr

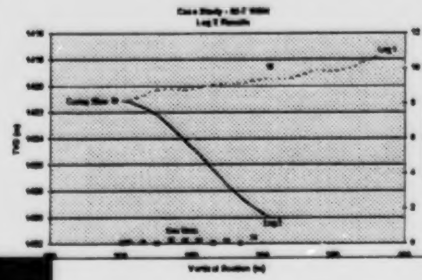
82-7 W6M Case Study - Leg 1



82-7 W6M Case Study

- No significant inflow from leg 1
- Sidetrack 3m out of shoe
- Start sidetrack with leg 1 BHA
- SABH @ 1.5 °
- Correlate depth at hot collar

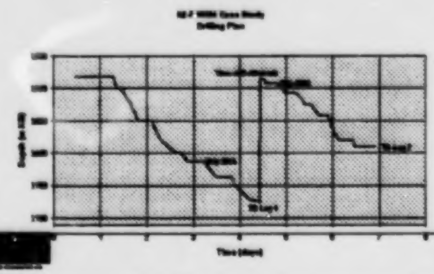
82-7 W6M Case Study - Leg 2



82-7 W6M Case Study
Leg 2 Results

- Drilled 1535 - 1640mMD
- Pann ~ 7500 - 12000 kPa
- Diesel / N2 @ 0.45 / 15 m3/min,
  then 0.50 / 0 m3/min
- ROP ~ 9 m/hr
- 2m of Belloy penetrated

82-7 W6M Case Study
Drilling Plan



Conclusions

- Objectives were met using CT UB
- Productivity of Montney known while drilling
- Effective open hole sidetrack
- Belloy was productive with minimal penetration
- Underlying water in Belloy was managed

The Use of Continuous Sucker Rod in the Shell House Mountain Field: A Case Study

D. Holden, N. Poetschke, D. Wiltse

Abstract

This field study was conducted on 22 pumping oil wells operating in the House Mountain Field in the Swan Hills area of Alberta, Canada. The 22 wells had either used continuous sucker rod (Corod) at one time or were currently using Corod as the production mechanism. The purpose of this study was to evaluate the performance of continuous rod compared to that of conventional coupled sucker rods. Because continuous sucker rod has only two couplings, it distributes contact wear along the entire length of the sucker rod string, as opposed to concentrating it at the couplings. This should reduce operating costs by alleviating rod and tubing failure frequencies, and indeed, this study finds that Corod significantly reduced failure frequencies in 77% of the wells (17 wells). Individual well performances varied, of course, but overall averages demonstrate that while using Corod, these wells had 66% fewer rod parts per year than wells using conventional rod. The same is true for tubing repairs where wells using Corod had 50% fewer repairs on average than wells using conventional rod.

House Mountain Field Background

The House Mountain field has produced from three cycles of Alberta's Middle Devonian Slave Point formation since the early 1960's. The field was put on waterflood in 1965, and the well depths range from 2,200m to 2,590m. The production zone is the Beaverhill Lake, which consists of a reef and shoal environment and is supported by a stromatoporoid platform. The original reservoir was estimated at 60 million cubic metres of oil, and 1996 estimates place potential recovery at 19 million cu m. In 1996, 20 horizontal and 146 vertical wells were producing approximately 800 cu m oil/day[1].

The particular wells included in this study are all vertical applications, and any horizontal wells included are completed in the vertical section. Most wells in this area experience paraffin and corrosion problems, both of which are controlled by monthly chemical treatments.

Research Methodology

This study was initiated at the request of Shell Canada Ltd. in the House Mountain Field of North Central Alberta. Shell wanted to know if there was a difference in the failure frequency between Corod and Conventional Sucker Rods. Shell field personnel provided a list of 22 active wells that had at one time used Corod or were currently using Corod. Also included were the complete well file histories. We analyzed the well files and summarized failures according to two categories: rod failures and tubing failures. Rod failures include parted rods, broken pins, parted wrench flats, and parted polish rods. Tubing failures refer to failures associated with tubing leaks. Pump changes and failures associated with pumps were not included in this study, although they are noted on the individual well histories. Where information was available, we have noted failure causes in the individual well summaries. The actual causes of the failures have not been analyzed as part of this particular study; instead, we focused on rod and tubing failure trends over time.

Corod & Mechanical Wear

Continuous sucker rod technology was first introduced in the mid-1960's to solve a number of problems associated with

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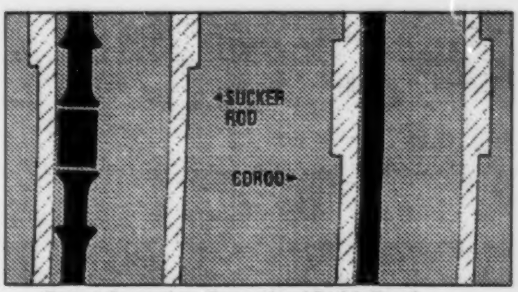
[1] Gregg Suziak and Dennis Walker. "Effective Reentry methods Reduce Cost and Optimize Production." Oil and Gas Journal. Vol. 94. No. 43. Oct 21, 1996. pg. 37-46.

conventional coupled rod. While Corod has only two joints, one at the top of the rod string and one at the bottom, conventional rod is coupled every 25 feet. A 5000ft well completed with a conventional rod string would therefore use 200 joints. Couplings are associated with three types of problems in typical vertical applications: box & pin failures, rod body breaks, and tubing leaks as a result of mechanical wear.

In a typical vertical well, box and pin (joint) failures are the largest contributor to sucker rod-related failures. This is because box and pin joints are often improperly made up. Despite advances in technology, typical coupling installation procedures are often archaic. Actual coupling installation varies from using precalibrated power tongs, to manually making the connection and periodically checking torque with a card, to manually making the connection without checking torque. In light of these practices, the reason for pin and coupling failures is self-evident. Corod, with only two connections, can all but eliminate pin and coupling failures, thus saving both time and money. Because it has no rod body couplings, Corod does away with loose joints, over-tightened joints, flawed-end failures, and in-coupling corrosion.

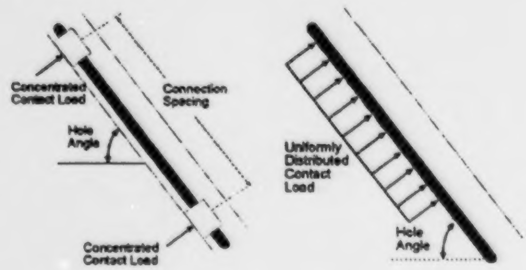
Conventional steel sucker rod strings can promote tubing wear and rod body breaks in some situations because of the concentrated contact load between the tubing and coupling. (See below.)



Contact Comparison Conventional Rod & Corod

Contact loads provide a good indication of potential rod/tubing wear problems and are easily calculated. Both gravity induced contact and curvature induced contact can negatively impact the wear rate of rods and tubing. While conventional rods contact tubing at concentrated points, continuous rod uniformly distributes contact with tubing, thus spreading wear out over a larger area. In fact, under the same conditions, the distributed contact loads are 50 to 75 times less with Corod than with conventional rod.

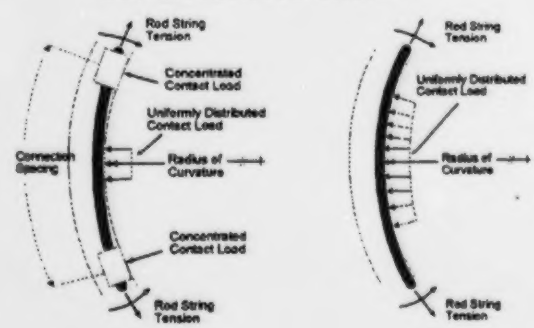
Gravity Induced Contact Load



There is a direct correlation between the angle of the hole (degrees) and the contact load. When using a 1-inch diameter conventional rod, the concentrated loading at 15 degrees is approximately 18lbs, while at a 30-degree angle, the rod's contact load would be approximately 32lb per coupling. Corod, with its contact loading distributed, is under 1 lb./ft at 15 degrees and under 1.5 lb./ft at 30 degrees. (See Appendix A) Obviously, the more slanted a well, the more significant the concentrated contact loading.

Operators must also contend with curvature-induced contact loading that occurs in relation to wellbore curvatures. Like gravity-induced loading, tension (or curvature)-induced loading is concentrated at the point at which the coupling meets the tubing. Continuous rod, having no couplings, contacts the tubing along a uniformly distributed curve. (See Appendix B)

Curvature Induced Contact Load



Results of the Study

Data Classification

In the following section, we have summarized the raw data taken from each well. We have broken out the failures into three categories: pump, tubing, and rod. The failure classifications are based on the field well files provided by Shell Canada, and although some interpretation was necessary, on the whole, the files were fairly comprehensive. Some wells' histories have been condensed so we could see the appropriate time frame and so this report was not too ungainly.

Tubing Repairs

Overall, conventional rod was used for a combined total of 437 years in 21 of the 22 wells. There were 88 tubing leaks, making for 0.2 tubing leaks per year per well. In other words, a tubing repair was necessary every five years on average. Corod, in use in the 22 wells for a compounded total of 181 years, saw 24 tubing leaks. This made for 0.1 tubing leaks per year per well, or a tubing repair every 10 years on average.

While using conventional rods, 18 of the 22 wells experienced tubing problems, while 9 wells using Corod had difficulties with tubing. Although 5 wells saw an increase in problems with tubing when utilizing Corod, 11 wells experienced a significant reduction in the average number of tubing jobs per year while using Corod. (For the purposes of this study, a significant reduction is equal to 50% or greater.)

In conclusion, the wells using Corod saw a 50% reduction in the number of tubing repairs per year, thereby doubling the life of the tubing.

Rod Parts

Wells using Corod experienced, on average, 66% fewer rod parts than wells using conventional rod. Although 5 wells experienced more parted rods since the installation of Corod, the use of Corod has resulted in measurable improvements in the number of parts per year in 16 wells (or 73%

	Corod					Conventional Rod				
	# Years	Total # Failures		Failures/ Year		# Years	Total # Failures		Failures/ Year	
Location	In Use	R	T	R	T	In Use	R	T	R	T
1	23	4	4	0.2	0.2	9	10		1.1	0.0
2	2	3		1.5		30	14	7	0.5	0.2
3	3	3		1.0		25	40	3	1.6	0.1
4	6	1		0.2		5	5		1.0	0.0
5	30	1	1	0.03	0.03	0				
6	23	4	5	0.2	0.2	10	8	1	0.8	0.1
7	7	1	1	0.1	0.1	25	28	3	1.1	0.1
8	2	4		2.0		32	1		0.0	0.0
9	5	1		0.2		25	25	13	1.0	0.5
10	8	1		0.1	0.0	30	22	9	0.7	0.3
11	5	0	0	0.0	0.0	8	9	1	1.1	0.1
12	6	2	3	0.3	0.5	26	27	11	1.0	0.4
13	1	1		1.0	0.0	11	8	6	0.7	0.5
14	1	5		5.0	0.0	33	20	1	0.6	0.0
15	3	4	1	1.3	0.3	29	16	7	0.6	0.2
16	2	1		0.5	0.0	28	34	9	1.2	0.3
17	6			0.0	0.0	26	29	3	1.1	0.1
18	6			0.0	0.0	24	25	4	1.0	0.2
19	7	4	4	0.6	0.6	22	38	6	1.7	0.3
20	7	5	1	0.7	0.1	4	12	1	3.0	0.3
21	23	4	4	0.2	0.2	8	17	1	2.1	0.1
22	5	1		0.2	0.0	27	27	2	1.0	0.1
AVERAGE	181	50	24	0.3	0.1	437	415	88	0.9	0.2

of the total). One particularly noteworthy well had experienced 17 parts over 8 years with conventional rod, while it saw only 4 parts in 23 years of Corod use.

Overall, there were 415rod parts in the 437 compounded years of conventional rod string use. This means that on average, there were 0.9 rod parts per year per well while using conventional rod. In other words, a rod string repair was necessary every 1.1 years on average. Corod, in use in the 22 wells for a total of 181 years, saw 50 rod string repairs. The average per well was therefore 0.3 failures a year, or a rod repair every 3.3 years. The wells using Corod consequently saw a 66% reduction in the number of rod string repairs per year, thereby tripling the run life of the sucker rod.

Overall

Of the 22 wells surveyed for this case history, 17 have measurably benefited from using Corod; these wells saw a 21% to 100% improvement in failure rates. Four wells, however, experienced an increase in failure rates upon using Corod, and one well never used conventional rod, making it impossible to compare performances. On average, the use of continuous sucker rod reduced failure frequencies by 64%.

Conclusions

Although the results of this study are measurable and impressive, there are limits to which Corod may be economically justified in today's business environment. An analysis of the current pulling expenses, cost of the installation, and the desired payout can help determine and justify the need for continuous rod. As an example of this kind of analysis, a recent study done by Stocker Resources in California included subsurface repairs, technical services, contract rig and labour, capitalized rods and tubing, and trucking and hauling. By doing this research, Stocker personnel determined that Corod had saved hundreds of thousands of dollars over a 3-year period[2]. In this particular scenario, Corod had been installed in 15 high expense wells to reduce hole-in-tubing related downtime and the associated well pulling expenses. In the end, continuous sucker rod was found to have saved over $350,000 in these 15 wells.

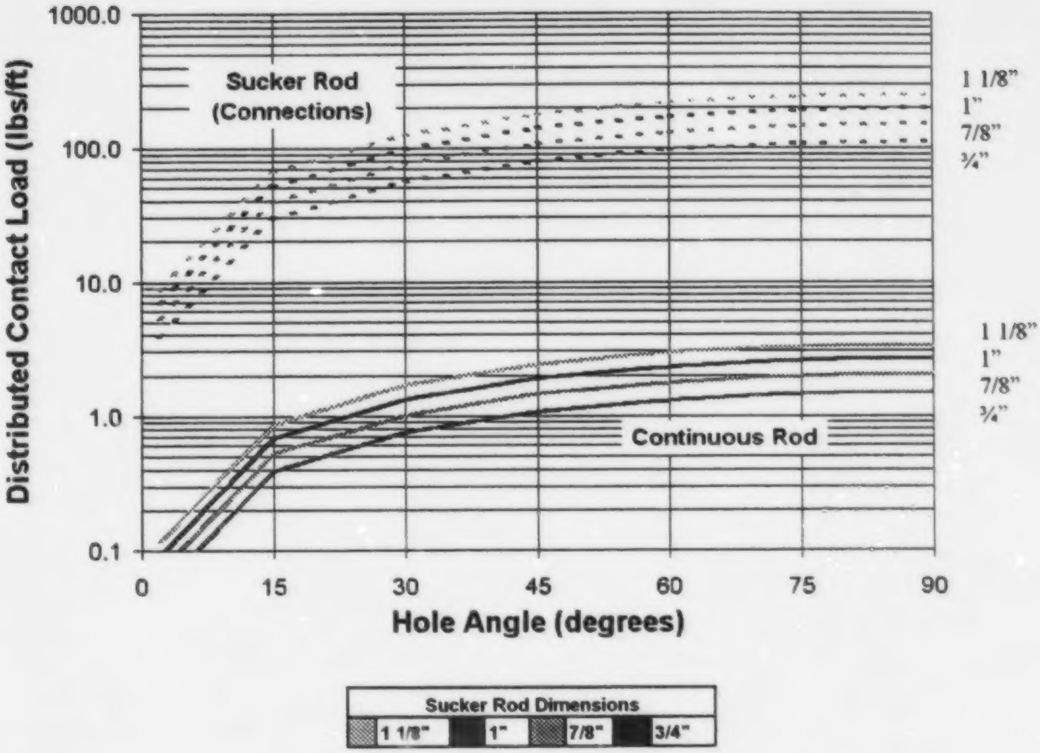
While no dollar figures have been associated with this Shell case history, a 64% improvement in repair rates represents a substantial cost savings. In the right application, continuous sucker rod can therefore optimize performance and save costs associated with rod and tubing repairs.

The authors gratefully wish to acknowledge the assistance of the staff of Shell Canada Limited in the preparation of this case study.

[2] D. J. Wiltse, and Michael L. Fernandez. "Continuous Sucker Rod Reduces Cost." The American Oil & Gas Reporter. Jan 1997.

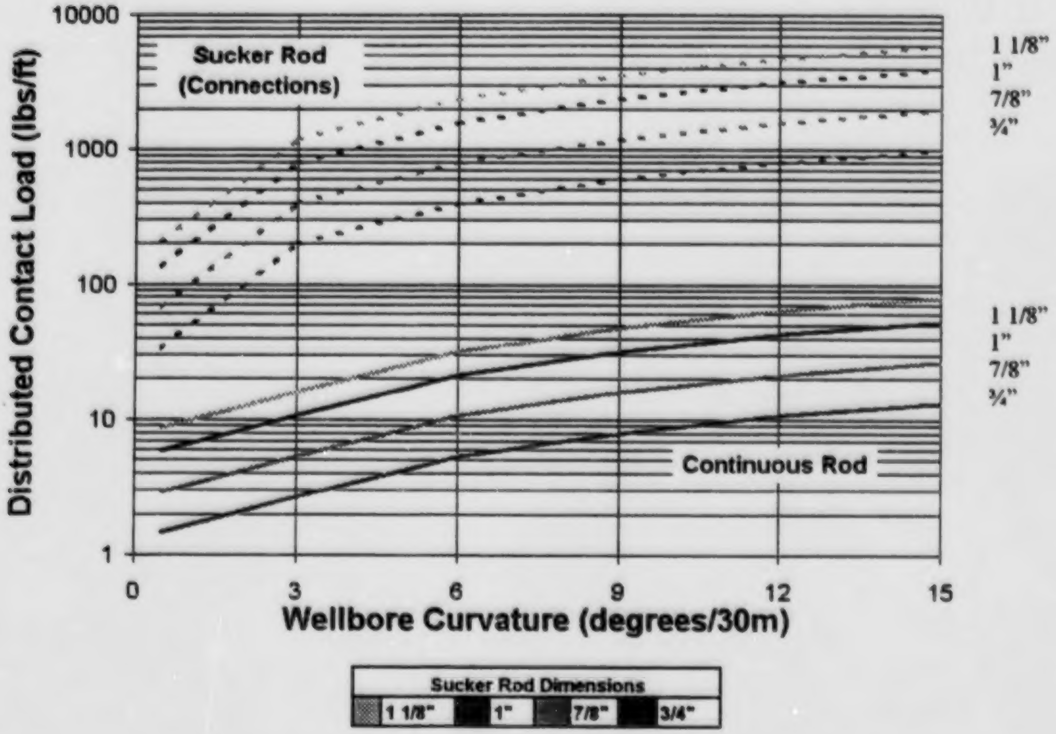
APPENDIX A

GRAVITY INDUCED LOAD COMPARISON
Conventional Coupled Rod & Continuous Sucker Rod



APPENDIX B

CURVATURE INDUCED LOAD COMPARISON
Conventional Coupled Rod & Continuous Sucker Rod



ELECTRIC SUBMERSIBLE PUMPING SYSTEMS FOR APPLICATIONS IN SOUR ENVIRONMENT

Andy W. Limanowka – Centrilift – Canada

ABSTRACT

This paper presents equipment modification requirements for resistance to harsh environments for petroleum production with the Electric Submersible Pumping System (ESP). These are to be used in hydrogen sulfide (H_2S)-bearing hydrocarbon service and when the fluids being handled are three-phase crude, water, and gas.

The ESP manufacturer developed two equipment standards for use in sour environments:

1. "ESP for Severe H_2S Environments" for application in well bores with:
    - up to 15% H_2S combined with 10PSIa or more partial pressure and 265PSIa or more total pressure; temperature from 150°F to 250°F BHT; pH4 or higher.
    - 15% or more H_2S combined with any partial pressure and total pressure; temperature from 150°F to 250°F BHT; pH5 or higher.
2. "ESP for High H_2S Environments" for application in well bores with:
    - up to 12% H_2S combined with any partial pressure and total pressure; temperature up to 150°F; pH4 or higher.
    - up to 6% H_2S combined with any partial pressure and total pressure; temperature up to 250°F; pH4 or higher.

Most of the engineering work was done in Canada with active engineering support from Claremore Engineering Department.

INTRODUCTION

Over the past five years the Canadian division of an ESP manufacturer has concentrated its energy and resources towards the development of ESP equipment for use in harsh environments, especially with high hydrogen sulfide concentration. This ESP manufacturer has been successful in H_2S environments such as South Sturgeon, Clive and Wimborne fields. As a result of the ESP manufacturer's experience in sour environments and equipment failure investigations, the metallurgy of some components as well as the design of ESP components were modified. Pumps, Rotary Gas Separators (RGS), seals and electrical connectors (2pce MLE) were modified to "High H_2S Environment Equipment Upgrades" or "Severe H_2S Environment Equipment Upgrades" standards. As we have not had a motor failure to date, no modifications were made to motor assembly. Equipment built according to "Severe H_2S Environment Equipment Upgrades" has been successfully operating in fields having on average: 20 to 44 mol% H_2S (very sour); 120,000 mg/l Cl^- (high); pH in range from 5.0 to 6.0; 1000 mg/l HCO_3; 350 mg/l SO_4; 44,000 mg/l Na; 20 000 mg/l Ca.

The NACE standard MR0175-97, "Sulfide Stress Cracking Resistant Metallic Materials for Oilfield Equipment", was used as a starting point for the equipment modifications. Materials included in this standard are resistant to, but not necessarily immune to, SSC under most service conditions. The acceptable materials and manufacturing processes listed in Sections 3 through 11 of NACE MR0175 should give satisfactory resistance to SSC in sour environments when the materials are manufactured to the heat treatment and mechanical properties specified, and used under the conditions specified. Metallic materials have been included in this standard as acceptable materials based on their resistance to SSC either in actual field applications, in SSC tests, or both. Many alloys included in the first edition of MR0175 had proved to be satisfactory in sour service even though they might have cracked in standard SSC tests, such as those addressed in NACE Standard TM0177. What this means is that final decisions on metallurgy can be made only based on field experience.

SOUR ENVIRONMENTS

A) Definition of Sour Environment based on NACE MR0175 :

Sour environments are defined as fluids containing water as a liquid and H_2S exceeding the limits defined below. Sour crude oil systems that have operated satisfactorily using standard equipment are outside the scope of this paper when the fluids being handled are either crude oil or two- or three-phase crude, water, and gas when:

- the maximum gas to oil ratio is 5000 SCF/bbl;
- the gas phase contains a maximum 15% H_2S;
- the partial pressure of H_2S in the gas phase is a maximum 10psia;
- the surface operating pressure is a maximum 265psia;

The satisfactory service of the standard equipment in these low-pressure systems is believed to be a result of the inhibitor effect of the oil and the low stresses encountered under low-pressure conditions.

Any environments exceeding the suggested safety envelope might cause SSC of susceptible materials. The SSC phenomenon is affected by complex interaction of parameters including:

- chemical composition, strength, heat treatment, and microstructure of the material;
- hydrogen ion concentration (pH) of the environment;
- H_2S concentration and total pressure;
- Total tensile stress (applied plus residual);
- Temperature; and
- Time

B) Evaluation of Corrosion of Steels in CO_2/H_2S Environments

Current understanding of H_2S effects on corrosion can be described in terms of a three-fold role:

1. At very low levels of H_2S (partial pressure < 0.01 psia), CO_2 is the dominant corrosive species, and at temperatures above 60°C, corrosion and any passivity is a function of $FeCO_3$ formation related phenomenon and the presence of H_2S has no realistic significance.
2. In CO_2 dominated systems, presence of even small amounts of H_2S (ratio of $pCO_2/pH_2S > 200$), can lead to the formation of an iron sulfide scale at temperatures below 120°C. However, this particular form of scaling, which is produced on the metal surface directly as a function of a reaction between Fe^{++} and S^{--} is influenced by pH and temperature. This surface reaction can lead to the formation of a thin surface film that can mitigate corrosion.
3. In H_2S dominated systems (ratio of $pCO_2/pH_2S < 200$), there is a preferential formation of a meta-stable sulfide film in preference to the $FeCO_3$ scale; hence, there is protection available due to the presence of the sulfide film in the range of temperatures 60 to 240°C. At higher concentrations and temperatures, $FeCO_3$ scale becomes the more stable pyrhotite. However, at temperatures below 60°C or above 240°C, presence of H_2S exacerbates corrosion in steels since the presence of H_2S prevents the formation of a stable $FeCO_3$ scale. Further, it has been observed that FeS film itself becomes unstable and porous and does not provide protection.

C) Importance of Water/Gas/Oil ratio

If the environment has GOR<5000SCF/bbl the tendency for corrosion and environmental cracking is often substantially reduced by inhibiting effect of the oil film on the surface. However, the inhibiting effect is dependent on the oil phase being persistent and acting as a barrier between the metal and the corrosive environment.

In oil systems with a persistent oil phase and up to 45% water cut, corrosion is fully suppressed, irrespective of the type of hydrocarbon. Relative wettability of the oil phase versus the water phase has a significant effect on corrosion. Metal surfaces that are oil wet show significantly lower corrosion rates.

In gas dominated systems, there are two measures to evaluate availability of the aqueous medium:

- If the operating temperature is higher than the dew point of the environment, no condensation is possible and corrosion rates are low.
- Corrosion under condensing conditions is a function of the rate of condensation and transport of corrosion products from the metal surface.
- If the total water in a condensing system as measured by the Water to Gas Ratio is less than 2 BBL water/MSCF gas corrosivity is substantially reduced.

D) Environmental Cracking

The two forms of environmental cracking are Stress Corrosion Cracking and forms of Hydrogen Embrittlement. Hydrogen Stress Cracking and Sulfide Stress Cracking are considered to be two forms of Hydrogen Embrittlement

Environmental Cracking (EC): Brittle fracture of a normally ductile material in which the corrosive effect of the environment is a causative factor.

Hydrogen Embrittlement (HE): A loss of ductility of a metal resulting from absorption of hydrogen.

Hydrogen Stress Cracking (HSC): A cracking process that results from the presence of hydrogen in a metal in combination with tensile stress. It occurs most frequently with high-strength alloys.

Stress Corrosion Cracking (SCC): Cracking of a metal produced by the combined action of corrosion and tensile stress (residual or applied).

Sulfide Stress Cracking (SSC): Brittle failure by cracking under the combined action of tensile stress and corrosion in the presence of water and hydrogen sulfide.

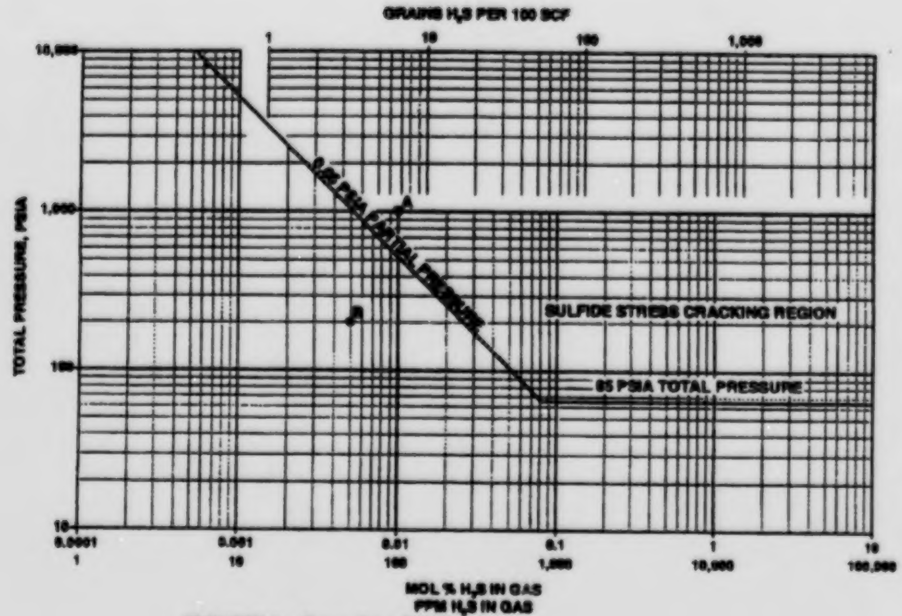


FIGURE 1: Sour Gas Systems

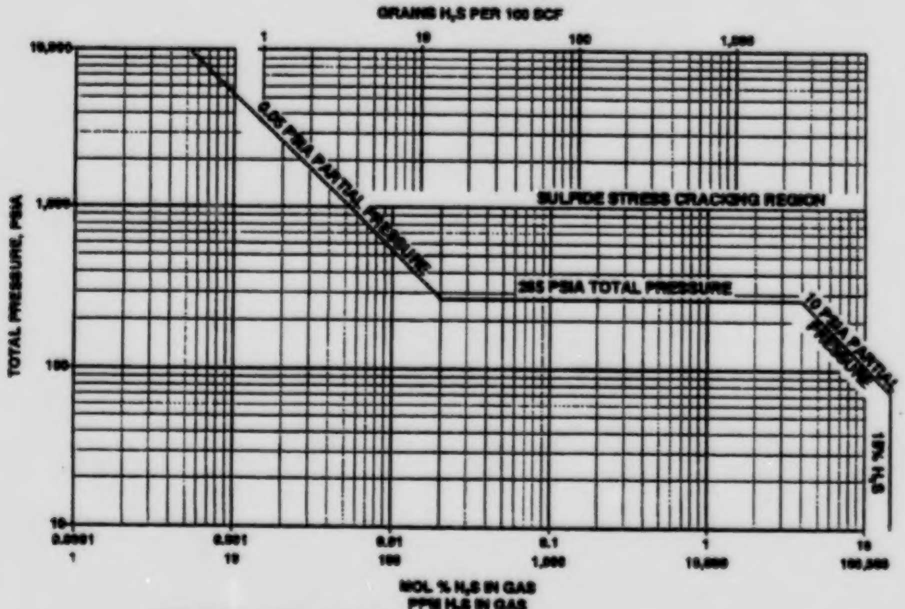


FIGURE 2: Sour Multiphase Systems

Metric Conversion Factor: 1 MPa = 145.089 psia

REASERCH AND DEVELOPMENT

1) NICKEL ALLOYS:

Intensive study on use of Nickel based super-alloys in ESP equipment was undertaken. Two engineering firms, Canspec Inc. in Edmonton and C&M Engineering Ltd. in Calgary, were involved in metallurgical analysis.

Nickel-based alloys constitute a family of alloys with increasing importance in many industrial applications because they can be corrosion resistant in a wide variety of service environments that range from sub-zero to elevated temperatures. Some types have an almost unsurpassed corrosion resistance in certain media, but nickel alloys are usually more expensive than iron-base or copper-base alloys, for example.

"Nickel alloys" are defined as alloys in which nickel is present in greater proportion than any other alloying element. The most important alloying constituents are iron, chromium, copper, and molybdenum and a variety of alloy classes are available.

Two groups of alloy classes can be distinguished: (1) alloys which depend primarily on the inherent corrosion characteristics of nickel itself (plus some influence of alloying elements), (2) alloys which greatly depend on chromium as the passivating alloying element (similar to the stainless steels). Usually, one distinguishes the following alloy classes :

A) Non-chromium-containing
- Nickel-molybdenum Alloys
- Nickel-copper Alloys

B) Chromium-containing
- Nickel-Chromium Alloys
- Nickel-Chromium-Molybdenum Alloy
- Nickel-Iron-Chromium Alloys
- Nickel-Iron-Chromium-Molybdenum

Solid Solution nickel-base alloys are generally used in the annealed or annealed and cold-worked conditions. Cold working can be achieved by a number of methods. These alloys are not intended to be strengthened by heat treatment. It was found that longtime aging of heavily cold-worked alloys such as N10276 and N06625 at around

315°C (600°F) and higher can be detrimental to hydrogen embrittlement resistance. This type of alloy was dismissed from use as a shafting material.

Precipitation Hardenable nickel-base alloys (e.g. Alloy 825, Alloys 31, 48, 718, 725, X-750, and 925) are normally used in: (1) solution-annealed, (2) solution-annealed and aged, (3) hot-worked and aged, or (4) cold-worked and aged conditions. It was found that with some of these alloys, specific heat treatments can cause precipitation of phases in the grain boundaries or grain growth. Both phenomena can be detrimental to hydrogen embrittlement resistance. Manufacturing technology, as well as quality control, seems to be critical. Material is electric arc melted and refined by AOD (Argon-oxygen decarburization) or VOD (Vacuum oxygen decarburization). VIM (vacuum induction melting) processing is also used. Some processes include ESR (electroslag re-melting) or VAR (vacuum arc re-melting). Environmental cracking resistance may vary among alloys manufactured by different processing routes. Chemical composition, temperature and final forming operations, as they affect microstructure and hardness level, can affect cracking resistance. It was noted that:

- Aerospace applications use different manufacturing routes, including heat treatment and may not be suitable for oil industry applications.
- The high nickel alloys are more difficult to cast than the common carbon steels and stainless steel alloys. The high nickel alloys are more prone to casting defects such as hot tears, cracking, porosity, and gassing. These defects may appear at any stage of the manufacturing process; shakeout, heat treating, machining, or final pressure testing.

  Ordering castings to current ASTM and ASME standards and/or trade-names does not guarantee the quality and purity of material necessary to obtain corrosion resistance equal to the wrought alloys and optimum casting integrity. Items that should be controlled include foundry processes, raw material quality, filler material composition, and heat treatment.
- Freckles (intermetallic phase of Mo, Cr, Ni, etc.), a metallurgical defect in large cross-sections, may be formed in alloys like N07718.
- The Sulphide Stress Corrosion Cracking (SSCC) threshold stress increased with decreasing H_2S concentration. Each material should exhibit an H_2S concentration limit below which SSC will not be observed on specimens stressed to 100% of the material yield strength. This concentration limit might decrease with increasing yield strength.
- The effect of operating temperature on the SSCC susceptibility is critical. Some materials such as carbon steel will show decreasing susceptibility to SSC with increasing temperature. In contrast, "Nickel Alloys" will show increasing susceptibility to SSC with increasing temperature. Ni-Cu alloys exhibits the greatest sensitivity to cracking in sour environments that Ni-Mo alloys
- In low temperature sour environments, cracking has been observed only when the nickel-base alloys have been coupled to carbon steel, thus cathodically polarizing them.

- Cracking of Nickel Alloys in sour solution at high temperature is related to anodic dissolution mechanisms.
- H_2S can lowered the pitting potential four times
- In environments that contain H_2S and S_8, CO_2 may inhibit cracking due to buffering action.
- H_2S is not necessary to cause cracking in presence of S_8 because of the local H_2S created by the reduction of sulfur.
- Sulfur affects cracking by increasing the anodic reaction or preventing repassivation of the alloy surface by excluding OH^- adsorption.
- Increasing pH prevents cracking.

2) NICKEL ALLOYS – CONCLUSION:

A) UNS N06625 (Ni-Vac625) was abandoned as a shafting material. Two other shafting materials were tested for load versus susceptibility to SSCC study. The NACE TM0177-96 method "A" was chosen for SSCC test at variable stress levels. Both materials are Nickel based super-alloys. Test results were satisfactory and threshold stress, as a percentage of yield strength, was assigned to each one for use in H_2S environments. Based on the test results and field experience, we could abandon expensive special shafting used with previous generation equipment. The material with higher threshold stress is utilized in pumps and intakes. Material with lower threshold stress is used with the seal. The seal shaft experiences lower stresses due to larger diameter and better operating conditions than pump or intake shaft.

B) The use of the snap ring made from Nickel alloy according to NACE MR0175 was limited to environments specified by "High H_2S Environment Equipment Upgrades" standard. It was found that residual tensile load is higher than threshold stress for this material at H_2S concentrations existing in Wimborne field. The snap rings were replaced by split rings in the pump, intake and seal for use in environments specified by "Severe H_2S Environment Equipment Upgrades", such as the Wimborne field

3) CORROSION-EROSION:

Intensive study on corrosion-erosion in ESP equipment was undertaken. "Canspec Inc." from Edmonton was involved in metallurgical analysis.

Erosion corrosion is the corrosion of a metal, which is caused or accelerated by the relative motion of the environment and the metal surface. Surface features with a directional pattern are direct results of the flowing media. Erosion corrosion is most prevalent in soft alloys. Alloys that form a surface film in a corrosive environment

commonly show a limiting velocity above which corrosion rapidly accelerates. Other factors such as turbulence, cavitation, impingement or galvanic effects can add to the severity of attack.

Prevention or Remedial Action

- selection of alloys with greater corrosion resistance and/or higher strength.
- re-design of the system to reduce the flow velocity, turbulence, cavitation or impingement of the environment.
- reduction in the corrosive severity of the environment.
- use of corrosion resistant and/or abrasion resistant coatings.
- cathodic protection.

The mechanism of erosion consists of sequential plastic deformation processes that account for each of the separate occurrences that result in the overall surface degradation. Erosion is not a result of the micro-cutting mechanism

4) CORROSION-EROSION – CONCLUSION

The redesigned Rotary Gas Separator, named Direct Fluid Entry was developed for 400 and 513 equipment. All designs and prototyping were completed in Leduc. The new design includes a modified base, inducer, spider bearing, rotor, compression tube and housing. The metallurgy for the rotor, compression tubes and base liner was changed to increase corrosion and erosion resistance. The DFE has lower flow tribulations compared to the standard RGS design, as well as areas of trapped fluid was eliminated in this design.

5) SEAL THRUST BEARING:

A new type of thrust bearing with a steel base and thrust runner was adapted to "Severe H_2S Environment Equipment Upgrades" standard used for second generation of equipment used in Wimborne field. This bearing has no Bronze, Brass or Stainless Steel components. The thrust load capacity was increased as well. Thrust bearing in the lower tandem is designed to take pump thrust load.

6) SEAL BAG:

The elastomer that was used in first generation ESP did not seem to be good enough. Two other elastomers, a special grade of Fluorocarbon and modified TFE Propylene, were chosen for second-generation equipment. The Fluorocarbon has excellent mechanical and chemical properties for use in sour environments. High-density molecular structure would prevent gas migration across the seal bag. During extended compatibility tests, it was found that this elastomer cannot be used in amine environments. Any amine used for well treatment will cause elastomer degradation in a

short time. Unfortunately, amines are used as inhibitors in Wimborne. Finally, a modified grade of TFE Propylene was used successfully as a seal bag material

7) SEAL BAG - CONCLUSION:

The ongoing intensive study on elastomer suitable for use as a positive barrier in ESP equipment is continuing. New bag materials were under investigation by Claremore Engineering and number of different elastomers was tested in our Cable Plant development laboratory. The downhole test was chosen as a final test due to the difficulty in simulating downhole conditions at the surface. Test vessel with new cables samples was installed downhole in February 1998 and pulled out in the third quarter of 1998.

8) QUALITY CONTROL and ASSEMBLY PROCEDURES:

Based on results of R&D, a new assembly procedure was developed. Metallurgy of all shafts was tested in-house with Texas Nuclear Alloy Analyzer (TNAA). A sufficient hardness test was adopted to establish the actual hardness of the material or component being examined. It was decided that individual hardness readings exceeding the value permitted by this standard could be considered acceptable if the average of several readings taken within close proximity does not violate the value permitted by this standard. No individual reading can be greater than 2 Rockwell C hardness scale (HRC) units above the acceptable value. An independent contractor was hired to perform metallurgy and hardness tests.

All new metallurgy shafts must have a Special Engineering serial number stamped on the front face in the upper section of the shaft.

New equipment standard known as "Severe H_2S Environment" was developed for use in environments similar to the conditions found in Wimborne.

1) SCALE PROBLEM:

All pumps built for this field are designed as floaters. On a number of occasions heavy scale locked the impeller on the pump shaft resulting in thrust bearing overload. The metastable iron sulfide (FeS) product of H_2S corrosion and water borne $CaSO_4$ are dominant scales found within equipment from the Wimborne field. The traces of nickel sulfide (Ni_3S_2 and NiS) and iron-nickel sulfide ($(Fe,Ni)_9S_8$) occurred as well. The chemical-treating program was upgraded as a result of equipment analysis. The sampling frequency was set to every two weeks.

2) CABLE ARMOR GENERAL CORROSION:

It was found that armor, on submerged portions of cable, has been attacked by general corrosion. General attack is typically caused by uniform general corrosion. Uniform corrosion can be described as corrosion reaction that takes place uniformly over the surface of the material, thereby causing a general thinning of the component and an eventual failure of the material.

Prevention or Remedial Action

- selection of a more corrosion resistant alloy (i.e. higher alloy content or more inert alloy)
- utilize coatings to act as a barrier between metal and environment.
- modify the environment or add chemical inhibitors to reduce corrosion rate.
- apply cathodic protection.

It was decided, at this time, to improve chemical-treatment other than upgrading cable armor to Monel. New cable designs are still under investigation. Based on laboratory testing performed by Cable Plant in Claremore, Oklahoma, a number of potential candidates were chosen for downhole load tests. The downhole test was chosen as a final test due to the difficulty in simulating downhole conditions at the surface. A test vessel with new cable samples was installed downhole in February 1998.

1) SOLUBILITY of H_2S in MOTOR OIL:

The solubility of hydrogen sulfide in mineral oil used in ESP motor was determined as a function of temperature. The saturation level was determined for two operating temperatures, 100°F and 300°F. The saturation at operating temperature was obtained from interpolation of test results.

The level of residual H_2S contamination in used motors was determined based on oil H_2S contamination. Two samples were taken: first from used motor before pit test, second from used motor after flush and pit test.

"ESP for SEVERE H_2S ENVIRONMENTS"

Equipment built to "ESP for Severe H_2S Environments" has been upgraded as follows:

1. PUMP: shaft metallurgy is upgraded to Precipitation-Hardenable Nickel Alloy for all horsepower requirements. No Stainless Steel, Brass or Bronze parts are allowed within the pump unless they are plated with corrosion resistant alloy. Carbon Steel, nickel reach austenitic cast iron and Nickel Alloys are the only materials used within the pump. Housing is externally coated with Nickel-Copper Alloy using a spray technology eliminating porosity of the coating. All snap-ring used within standard

assembly are replaced with split-ring made from Nickel-Copper Alloy. Only TFE Propylene o-rings are used.

QUALITY CONTROL: As standard procedure, metallurgy of all components is verified in our shop upon assembly, using chemical testers and Texas Nuclear Alloy Analyzer (TNAA). All shafts have to be stamped with correct part numbers.

2. INTAKE: shaft metallurgy is upgraded to Precipitation-Hardenable Nickel Alloy for all horsepower requirements. No Stainless Steel, Brass or Bronze parts are allowed within the intake unless they are plated with corrosion resistant alloy. Carbon Steel and Nickel Alloys are the only materials used within the intake. Housing is externally coated with a Nickel-Copper Alloy using spray technology eliminating porosity of the coating. All snap-ring used within standard assembly are replaced with split-ring made from Nickel-Copper Alloy. Only TFE Propylene o-rings are used.

   QUALITY CONTROL: As standard procedure, metallurgy of all components is verified in our shop upon assembly, using chemical testers and Texas Nuclear Alloy Analyzer (TNAA). All shafts have to be stamped with correct part numbers.
3. RGS: shaft metallurgy is upgraded to Precipitation-Hardenable Nickel Alloy for all horsepower requirements. No Stainless Steel, Brass or Bronze parts are allowed within the intake unless they are plated with corrosion resistant alloy. Carbon Steel, WC and Nickel Alloys are the only materials used within the intake. Housing is externally coated with Nickel-Copper Alloy using spray technology eliminating porosity of the coating. All snap-ring used within standard assembly are replaced with split-ring made from Nickel-Copper Alloy. Only TFE Propylene o-rings are used.

   QUALITY CONTROL: As standard procedure, metallurgy of all components is verified in our shop upon assembly, using chemical testers and Texas Nuclear Alloy Analyzer (TNAA). All shafts have to be stamped with correct part numbers.

4. SEAL: Standard configuration is a double-bag (one bag per section) tandem seal. High-density TFE Propylene elastomer for bags and Nickel-Copper Alloy bag clamps are used. Nickel-Copper super-alloy shafts are used in both sections. Corrosion resistant bushings are used in the upper guide and head of upper tandem section. Two premium face mechanical seals with Nickel-Copper Alloy hardware are used in upper tandem. Carbon Steel and Nickel Alloys are the only materials used within upper tandem with the exception of thrust bearings and check valves. A special grade of Stainless Steel is used for the check valve body. Housing is externally coated with Nickel Alloy using spray technology eliminating porosity of the coating. Only TFE Propylene o-rings are used. All snap-ring, with exception of thrust runner snap ring, used within standard assembly are replaced with split-rings made from Nickel-Copper Alloy. Precipitation-Hardenable Nickel Alloy snap rings is used with thrust runner. Thrust load is transfer to Lower Tandem which utilize Corrosion Resistant thrust bearing.

   QUALITY CONTROL: As standard procedure metallurgy of all components is verified in our shop upon assembly, using chemical testers and Texas Nuclear Alloy Analyzer (TNAA). All shafts had to be stamped with correct part numbers.

5. MOTOR: Housing is externally coated with a Nickel-Copper Alloy using spray technology eliminating porosity of the coating. Nickel-Copper alloy fill valve and vent plugs are used. High-density TFE Propylene elastomer O-rings and a special grade of motor oil are used as well. No Stainless Steel, Brass, Bronze or Copper parts are allowed within the I-block unless they are plated with a corrosion resistant alloy. Nickel alloy thrust runner key and split ring and High Load thrust runner are the only allowed components. All copper wires within stator are Epoxy capsulated.
6. MLE: "Two Piece Lead-on-Lead" pothead has nickel rich austenitic cast iron body, double metal-elastomer sealing and Lead sheath cable with Monel armor.
7. CABLE: Lead sheath cables with carbon steel armor. No flat guards are used. Monel bands and clips are standard.
8. TUBING: J55 carbon steel and Monel standing valve.
9. SCREENS: Only Carbon Steel or Nickel Alloy metallurgy allowed.
10. FASTENERS: Monel fasteners for all joints.

CONCLUSION

We have not yet had catastrophic failure of any piece of equipment built according to "Severe H_2S Environment Equipment Upgrades" standard. It appears that, at this moment, reservoir dynamics, scale problems, general corrosion on cable armor and proper chemical treatment are the key directions in run time improvement.

The equipment developed for this type of is extremely specialized. It is developed for fields with downhole environments similar to Wimborne and would definitely be overkill in less harsh environments.

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A NEW TECHNIQUE FOR CLEANING HORIZONTAL WELLBORES

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ABSTRACT

Plugging of horizontal wellbores can lead to significant loss of productivity and can nullify the benefit of a horizontal wellbore that is expensive to create. Cleaning horizontal wellbores is a formidable challenge. The problem is particularly complex for heavy oil formations that show asphaltene, sand and other difficult-to-remediate problems. This paper aims at developing a new technique that can effectively clean up a horizontal wellbore without requiring expensive workovers. The technique involves the use of ultrasonic treatment coupled with foam treatment. Initial experiments show that ultrasonic treatment can reduce plugging in two ways – the first is the reduction in oil viscosity (especially in the presence of asphaltic crudes) and the second is the ability of ultrasound to keep particles in suspension. The second effect can be due to generation of microbubbles. The process is coupled with in situ generation foam. In order to generate foam, a particular type of surfactant is chosen from a selection of wide range of surfactants supplied by the service companies. While the design of the device that couples both these effects need to be optimized, initial series of experiments show good promises.

FEASIBILITY OF AIR INJECTION-BASED PROCESSES FOR WILLISTON BASIN RESERVOIRS

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A. K. Singhal

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Calgary, Canada

OUTLINE

- In-situ combustion (ISC) as an air injection process
- Types of air injection processes
- Spontaneous ignition and N_2 MMP
- Williston Basin air injection projects
- Novel thermal recovery technology
- Screening criteria for air injection-based EOR processes

ISC as an Air Injection Process

- Two phases: initiation of the process (ignition) and propagation of the ISC front
- Both **h**igh **t**emperature **o**xidation (HTO) and **l**ow **t**emperature oxidation (LTO) occur
- ISC process definition assumes the HTO is present. Therefore, a peak temperature (associated to an ISC front) can be defined

Four Types of Air Injection-Based Processes

FOR HEAVY OIL RESERVOIRS

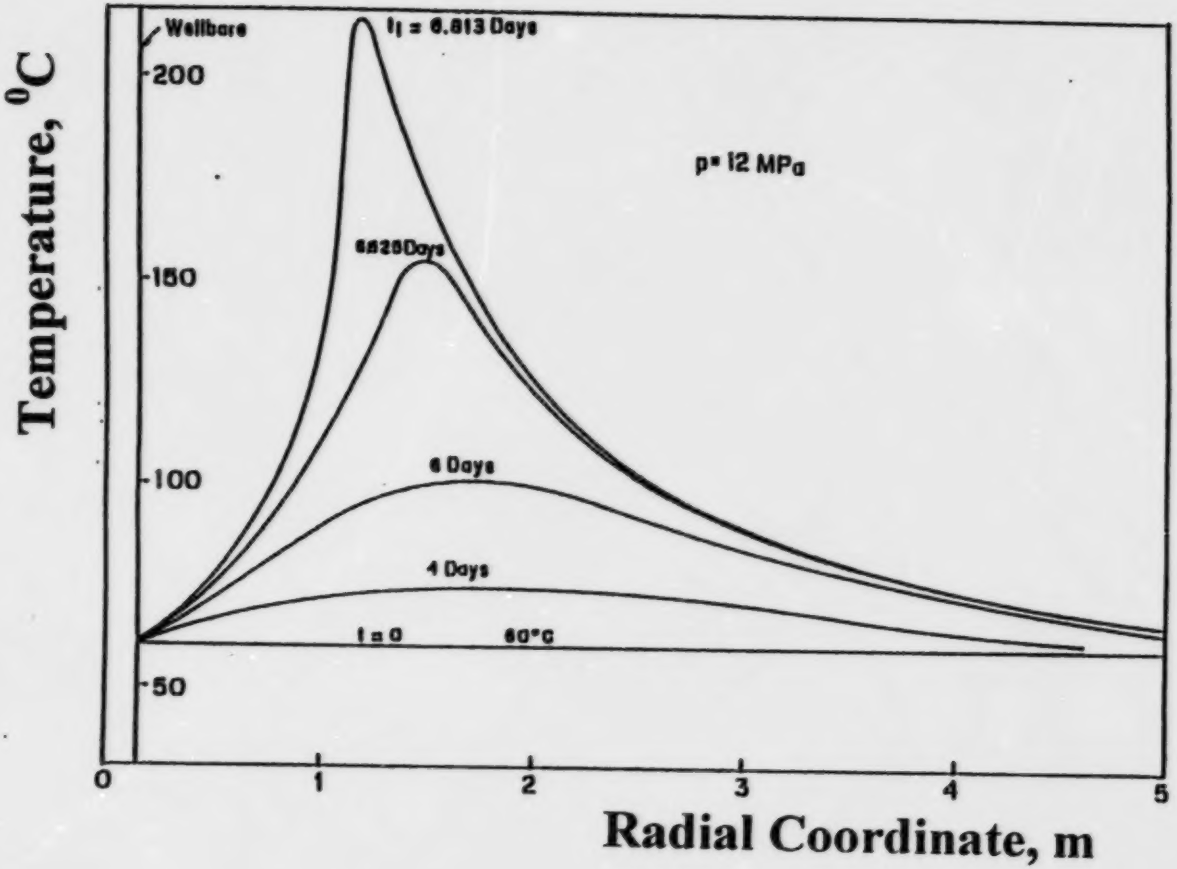
- Immiscible air flooding with intensive oxidation: **HTO-IAF ; (ISC)**
- Immiscible air flooding without intensive oxidation: **LTO-IAF**

FOR LIGHT OIL RESERVOIRS

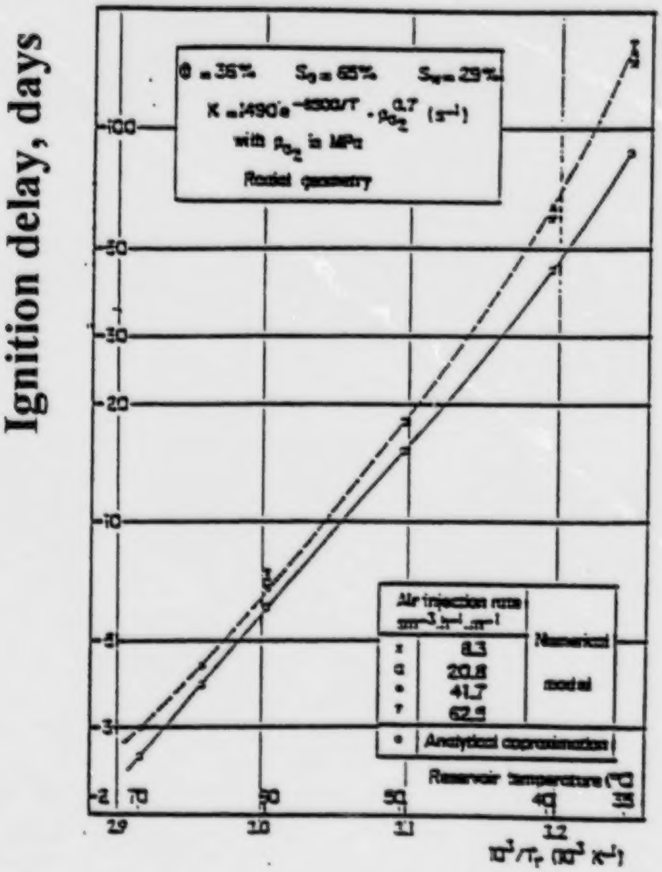
- Miscible air flooding with intensive oxidation: **HTO-MAF**
- Miscible air flooding without intensive oxidation : **LTO-MAF**

SPONTANEOUS IGNITION

- Definition
- How it happens
- Advantages
- Disadvantages



Radial temperature profiles in the reservoir during the ignition delay[6].



Effect of reservoir temperature and air injection on the ignition delay[6].

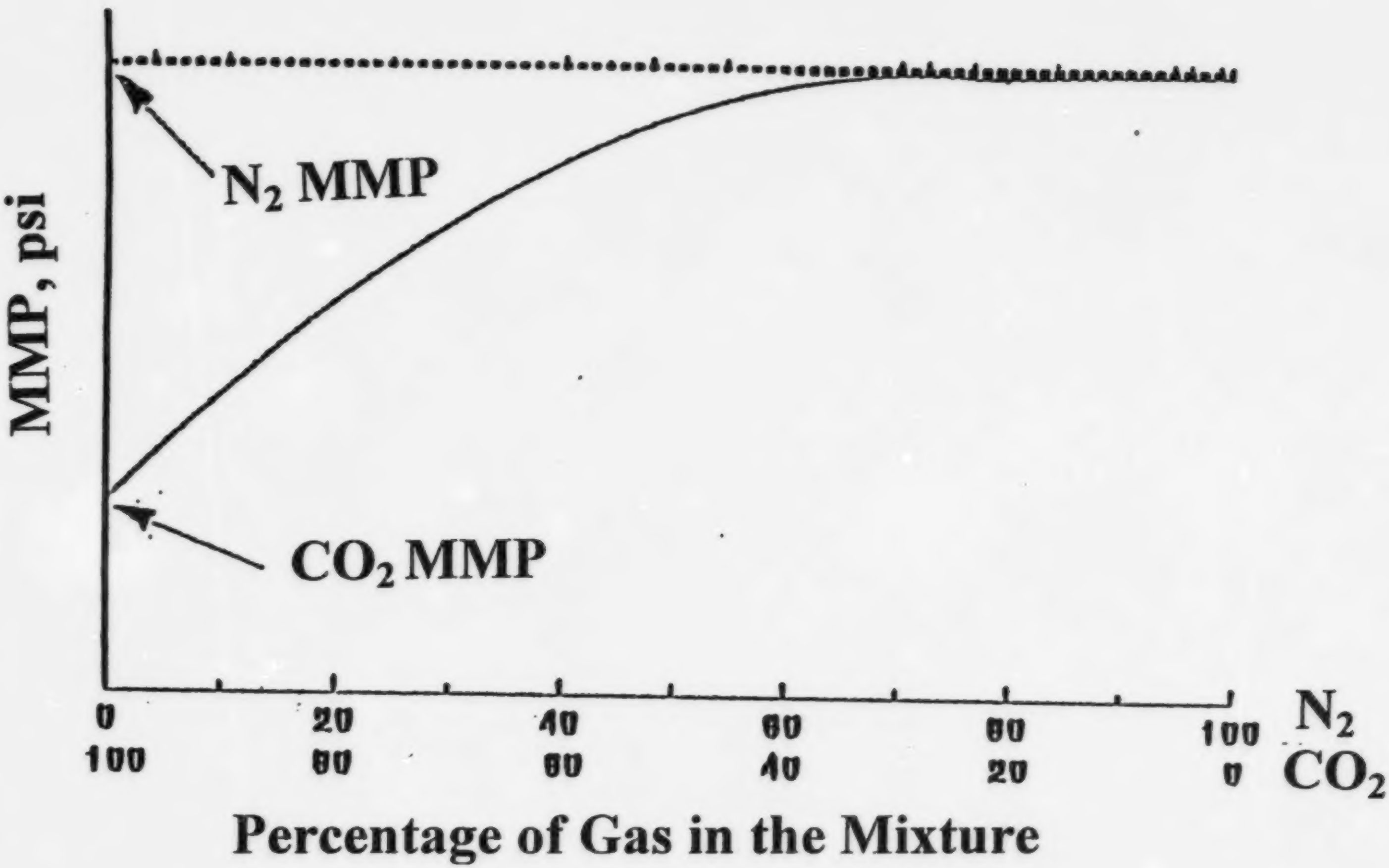
___ Using an analytical model

\- - - Using a numerical model

MMP for Miscible Air Flooding

- N_2 MMP is used
- $CO_{2\,MMP} << N_2$ MMP
- Why: $CO_2\% < 14\%$ in the gas generated
- $CO_{2\,MMP}$ when N_2 is an impurity and N_2 MMP when CO_2 is an "impurity"

Illustration of Minimum Miscibility Pressure (MMP) Variation for a N_2-CO_2 Mixture



Air Injection Field Projects

A) Intended as an ISC process

* Heavy oils
* intermediate and light oils

B) NOT NECESSARILY intended as an ISC process (usually in the very light oil , high temperature, low permeability reservoirs)

Classic ISC Processes

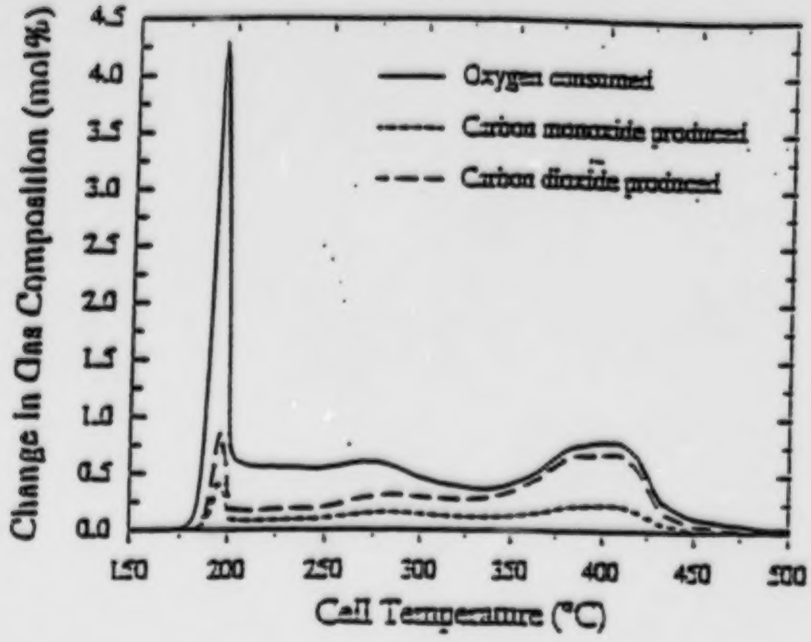
- Commercial application to heavy oils mainly (lowest viscosity 50-70 mPa.s)
- Worldwide > 12 commercial projects; highest degree of success for oil reservoir with viscosity > 400-500 mPa.s
- Labor intensive EOR process
- Problems: pollution and corrosion; very impredictable in nature-pilot absolutely necessary

ISC Applied to Intermediate and Light Oils (2-50 mPas)

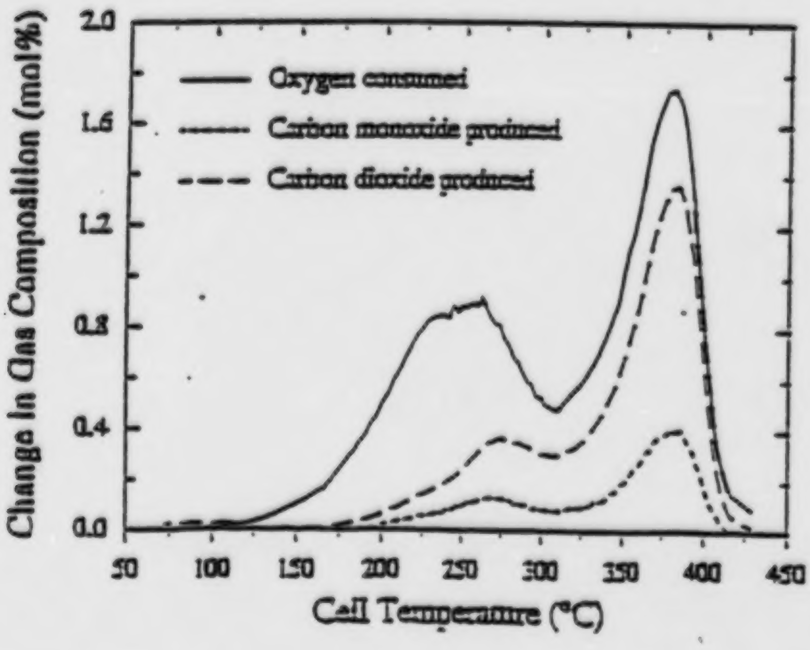
- Lowest viscosity for which a high peak temperature still exists (2 mPa.s)
- The peak temperature seems to be lower than 400 ^{0}C
- No commercial operation

Air injection Projects Intended NOT NECESSARILY as ISC Processes

- Known as high pressure air injection (HPAI) projects
- Main features: high depth, very high reservoir temperature (> 80^0C)
- CO_2 > 14%. What process occurs? HTO-MAF or LTO-MAF? Not clear yet.



Typical light oil ramped temperature oxidation test[33].



Typical heavy oil ramped temperature oxidation test[33].

VERY LIGHT OIL - AIR INJECTION PROJECTS

DEPTH: 600 -12,000 ft
RESERVOIR TEMPERATURE: 94-104^{0}C

FIELD, COMPANY, COUNTRY	Rock type	Pay Thic-kness m	Inj. Pressure psi	Porosity %	Perm mD	Oil Visc mPa.s	Daily Oil Prod. by ISC BBL/D	Air/Oil Ratio SCF/BBL
WEST HACKBERRY, Amoco, Louis., USA	S	10*	-	27	300	0.9	-	-
SLOSS, Amoco, Nebr, USA,		6	3,600	11	190	0.8	480	16,900
MPHU, Continental, USA	D&L	6	4,400	17	5	0.5	600	12,000
BUFFALO, Continental, USA	D	?	4,400	19	18	0.5	2,500	10,000
Madison CAPA, Koch Expl., USA	L	?	4,400	11	10	0.5	-	20,000

LEGEND
* DIP = 23-60 degrees
D = Dolomite; L = Limestone
MPHU = Medicine Pole Hills Unit

Other Air Injection Projects

- Horse Creek, Williston Basin, ND
- Eagle Springs, Nevada, USA
- One project in Indonesia
- One project in Argentina

WILLISTON BASIN AIR INJECTION-BASED PROCESSES

(Main features - prospects for improvements)

LOCATION MAP

WILLISTON BASIN AIR INJECTION-BASED PROJECTS - OBSERVATIONS

- Rock: very low permeability dolomite; NOT fractured
- Micro- versus extended macro-fractures
- Gas processing plant to recover NGL
- Successful application at 17$/bbl of oil for an application in patterns (not peripheral line drive)

WILLISTON BASIN AIR INJECTION PROJECTS

DEPTH: 600 -12,000 ft
RESERVOIR TEMPERATURE: 94-104^{0}C

FIELD, COMPANY, COUNTRY	Rock type	Pay Thic-kness	Inj. Pressure	Porosity	Perm	Oil Visc	Daily Oil Prod. by ISC	Air/Oil Ratio
		m	psi	%	mD	mPa.s	BBL/D	SCF/BBL
MPHU, Continental, USA	D&L	6	4,400	17	5	0.5	600	12,000
BUFFALO, Continental, USA	D	?	4,400	19	18	0.5	2,500	10,000
Madison CAPA, Koch Expl., USA	L	?	4,400	11	10	0.5	-	20,000

LEGEND
D = Dolomite; L = Limestone
MPHU = Medicine Pole Hills Unit

DISPLACEMENT MECHANISMS

- Reduction of viscosity - not a significant mechanism
- Achievement of high vol. sweep efficiency may be - high conformance factor (CF)

Ex: - May Libby project, Delhi Field, USA; 3mPas oil, h=9ft, CF=100%

- Delaware Childers, OK, 6 mPas oil, h=42 ft, CF= 65%.

Piloting of an Air Injection Project - 3 Conditions for Success

- Pilot located at the uppermost part of structure
- Vertical or pseudo-vertical flooding whenever possible
- Use of peripheral line drive operation, as opposed to patterns operation, if possible

Use of Horizontal Wells as Air Injectors: **Serious Safety Concerns**

- Large storage of gas within horizontal section of the wellbore: substantial explosion hazard
- Shut-in periods and /or uncontrolled backflow
- Better to avoid using them unless very enhanced technical precautions are taken

A NEW THERMAL RECOVERY TECHNOLOGY

- THAI -

TOE-TO-HEEL AIR INJECTION

Petroleum Recovery Institute

Fig.1 Concept of Toe-to-Heel Air Injection Process (THAI)

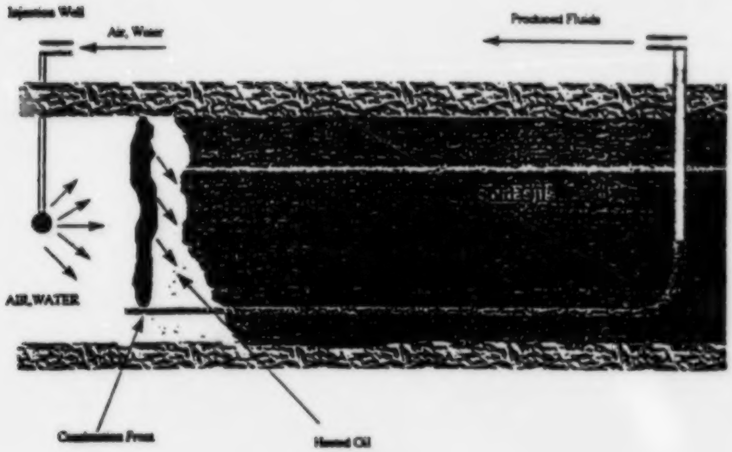


Fig.2 Production mode of Toe-to-Heel Air Injection Process (THAI)

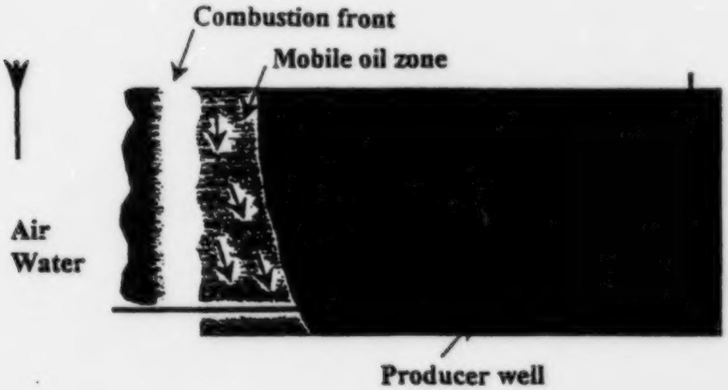
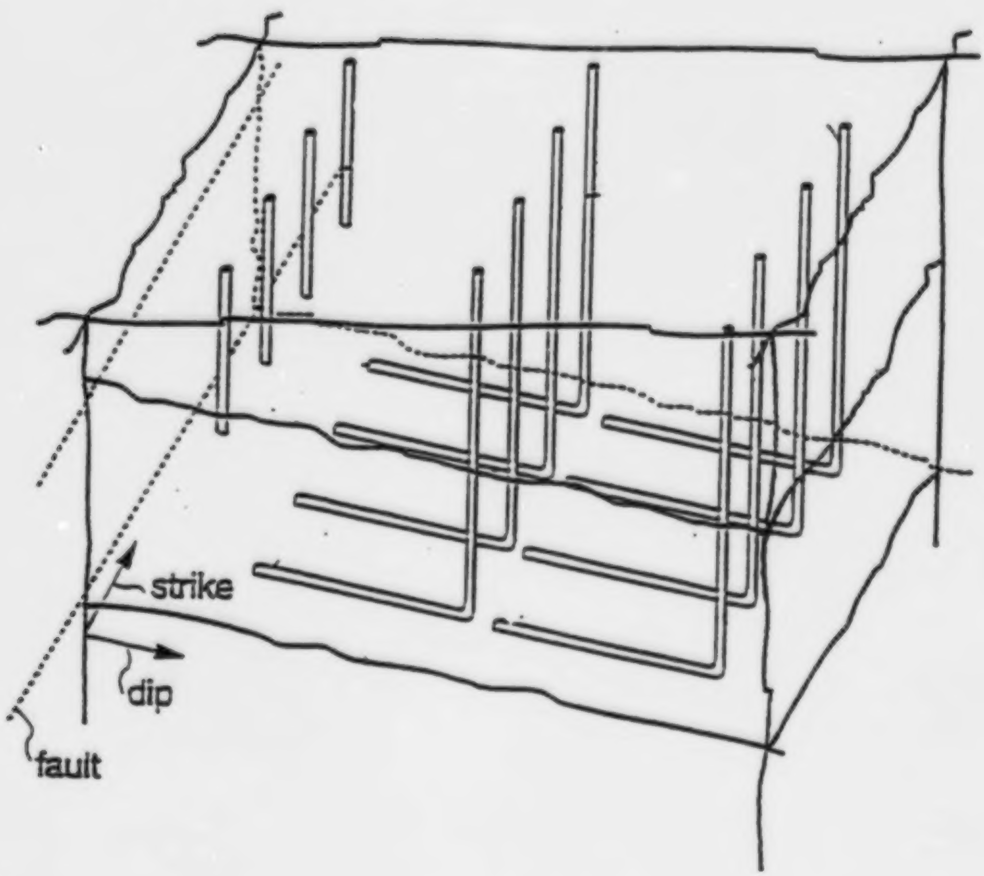


Fig.3 Mobilised oil draining from narrow zone into exposed section of horizontal producer well

TOE-TO-HEEL AIR INJECTION - THAI

PERSPECTIVE VIEW OF THE RESERVOIR FOR THE THAI TECHNOLOGY APPLICATION



Petroleum Recovery Institute

SCREENING CRITERIA

- IN THE NEXT SLIDE: Only for HTO-MAF (HPAI). Same criteria as for N_2 miscible flooding, plus a warm reservoir ($T > 80^0C$)

SCREENING CRITERIA for MAF-HTO

- Oil viscosity < 2 mPas
- Depth >2000 m
- Res. Temp > 80^0C
- N_2 MMP < Init. Res. Pressure
- Net pay thickness > 3 m
- Oil saturation > 30%
- No fracturing, large gas cap or bottom water

LIMITATIONS, FUTURE PROSPECTS

- A certain amount of speculative effort is included in the classification of air injection processes
- More systematic investigation of the air injection processes - both in laboratory tests and in well instrumented field pilots - will throw more light about the mechanisms of these processes.
- Peripheral line drive application: recommended

Diagenesis - the maker and breaker of reservoir rocks in the Frobisher Beds of southeastern Saskatchewan: implications to horizontal wells

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The carbonate ramp is the setting for Mississippian sediment accumulation in the Williston Basin. It varied through time from distally steepened (Souris Valley Beds) to shallow sloping (Midale and Ratcliffe Beds) . The steepness of the ramp slope played an important role in the pattern of distribution of carbonate sediments types. The Frobisher ramp was sufficiently steep that a coated grain-skeletal, fringing bank was accreted to the shoreline and prograded basinward for some distance (Figure 1). Progradation was supplement by vertical accretion with the result that the Frobisher interval is dominated by coated grain deposits intermittently separated, vertically, by thin dense micritic-appearing beds. There were sufficient periods of exposure during aggradation that the bank contains evidence of the effects of peritidal and vadose processes, including cyanobacterial or microbial micritization, fenestral pores as well as coniatoids and pisolite and typical tufa-like textures similar to those of beach rocks found on modern carbonate shorelines. Bahamian-type and intraclastic ooids are interspersed as lenses and discrete layers with the coniatoids and pisolites. Vertical growth of the bank terminated in a supratidal flat containing supratidal and salina evaporites.

Pore types in the Frobisher Beds include: fenestral and moldic vugs, intraparticle pores in skeletal debris; interparticle pores, particularly in intervals composed of Bahamian-type ooids; and, intercrystal pores in the micritic and dolomicritic rocks. Fenestral and moldic vugs are the most common forms. The geometry of fenestral pores is variable and categorizing them according to a classification proposed for Holocene types (Table 1) may help to evaluate fluid migration pathways in Frobisher reservoirs. Laminoid fenestrae appear to be common in coated grain intervals with a high proportion of micritic cement. By contrast, the irregular fenestrae prevail more in the grainstones or packstones, and tubular fenestrae are generally associated with coated grain wackestones or wackepackstones. Moldic pores include dissolved ooids as well as pisolites, coniatiods and intraclastic coated grains of which the nuclei have been dissolved. The moldic pores after coated grains in which only the nuclei are dissolved, rarely contribute to effective

porosity as they are invariably unconnected, but moldic pores of totally dissolved coated grains, similar to those of dissolved skeletal debris do play an important role in the storage capacity of the rocks.

Diagenesis has played a major role making and breaking reservoirs in Frobisher coated grain rocks. The significant processes are calcite cementation, microbial and chemical micritization, anhydritization, dolomitization, solution and solution compaction (Figure 2). There are at least four recognizable stages of calcite cementation, three of which show evidence of formation during initial sedimentation and burial, and the fourth following exposure during the pre-Mesozoic hiatus. The procedure at that time included exhumation of cement-filled fenestral and moldic pores accompanied by corrosion of some pore walls, followed by cementation upon re-burial. Unlike fenestral and moldic pores, the interparticle porosity in deposits of Bahamian-type ooids was tightly occluded during early stages of cementation and little exhumation occurred during exposure. Thus these rocks form relatively impermeabile layers in the Frobisher succession and play a role in the compartmentalization of the reservoirs. Compartmentalization is also effected by stylolitization of intervals with high concentrations of insoluble material. The stylolitization may be accompanied by chemical micritization of the undissolved carbonate rock material. Present reservoir porosity was created by late stage solution that removed the occluding cements and enhanced the geometry of the pores systems. However, were the stylolitized or tightly cemented intervals are closely spaced, the rocks may have developed strong horizontal permeability through channel-like pores producing a poor k_v/k_h ratio. A horizontal well drilled into rocks with these characteristics may have to drain a fairly extensive horizontal area to be productive and may readily communicate with vertical wells in the same reservoir.

The complete text of this paper can be found in Summary of Investigations 1999, Saskatchewan Geological Survey, Sask. Energy Mines, Misc. Rep. 99-4.

Figure 1

Table 1

TYPE	VOID SIZE	COARSE	MEDIUM	FINE
Laminoid	Average Height (mm) Average Length	5 10-30	1-5 10-30	1 5-30
Irregular	Average Height (mm) Average Length	5 5-10	1-5 1-5	1 1
Tubular	Average diameter (mm)	5	1-5	1

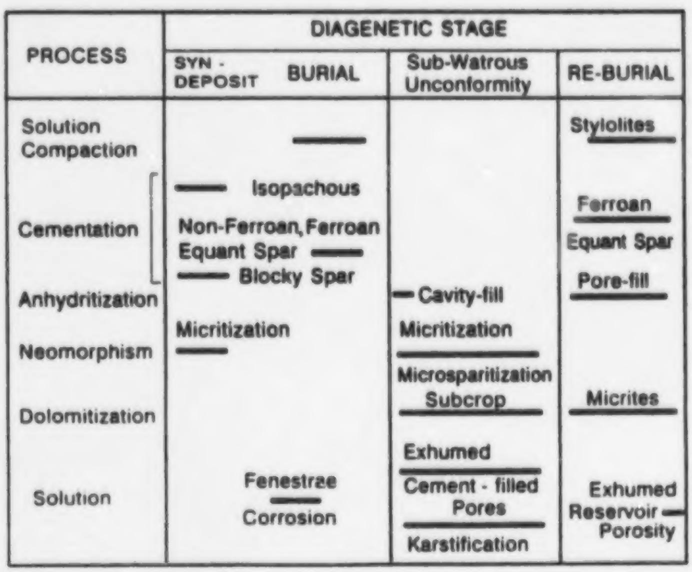


Figure 2

Ranking Horizontal Wells

Robert J. MUNDAY April 1999
306-731-2176

Quantifying mineral resources is thwart with problems, as is presently being 'duked-out' by executives of Blue Range Resource Corp. and Big Bear Exploration Ltd. Do geologists:

*) Make best estimates from available information plus logical reasoning;

*) Remain silent even as investment funds are not best utilized at the drilling stage, from fear of making mistakes.

I have no problem in making best estimates. Oil in the ground is especially difficult as at the drilling stage we can neither see nor measure it, just infer. We end up with estimates. Mine tend to underestimate *Good-Excellent* positions and overestimate *Fair-Poor* positions (Figure #1). Financial analysis Fibonacci lines do the same. If a junior oil company does not have a stable of *Good* wells plus at least one *Excellent*, it will stagnate. A company cannot pay its expenses, repay debt and expand from wells ranked *Fair-Poor*.

Anticipating a horizontal well's productivity, its **Ranking**, has become an expectation of geologists supervising at the wellsite. They have observed most aspects of the project and are in a position to make recommendations for incremental expenditure. For instance: drilling on into another SU; cutting another leg; sidetracking into better 'pay'; even plugging back and redrilling. If successful, these incremental investments provide some of the richest NPVs. The rig has been mobilized, *build* is cased so ongoing drilling is costing in the order of $100/m new horizontal wellbore at typical ROPs. Four examples are provided. Well identifications are omitted out of respect for client confidentiality. All provided data resides within non-confidential files of the Governments of Alberta, Saskatchewan and Manitoba.

1) **Re-entry opportunity**: a sharp eyed Vice President spotted a 'depleted' well in the Midale Marly pool, negotiated farm-in, then mobilized a rig to re-enter and sidetrack into suspected by-passed pay (Figure #2). This investment has a neutral NPV at $7/bbl (Oil price in $US), mainly a result of incremental production (Figure #3) being within the royalty window, infrastructure in place.

2) **Sidetrack into better 'Pay'**: another well in the Midale Marly pool had been drilled following seismic prognosis and *Excellent* reservoir conduit was glimpsed three times. The operator had to be convinced into drilling a $30,000 Leg #2 (Figure #4) that probably provides most the 20,000m^3 oil, which has been produced todate. This incremental investment yields a net $400,000 NPV when compared to an adjacent similar well not redrilled into 'conduit'

3) **Keep on drilling**: after 18 days drilling in the Alida member, the President called "Shut down operations". At the end of the last single, 1000mE on Leg #3 (Figure #5), a gas kick was observed, enough to convince the geologist that drilling should continue: it was 1800hrs on a Friday in Calgary and no-one was by their phones. Eventually the President was tracked down and permission obtained to continue drilling. By Saturday evening another 200m of *Good-Excellent* pisolitic shoal had been accessed. Drilling was then terminated as pay appeared to plunge and chasing it would have necessitated a new bit plus much downside *setting*. This investment provides a neutral NPV at $20 oil that was the prevailing price at drilling. Without the additional drilling it would provide -ve NPV. As it still has CUMOP <5000, it's a candidate for re-entry.

4) *Evaluate all the information:* three parallel horizontal wells were drilled into a bitumen saturated sand in Alberta with designs to steam flood into the central well (Figure #6). A few vertical observation wells were used as control. Enthusiasm to get the project completed had the horizontals drilled before the verticals were evaluated, some were not even drilled! Several $million of steam was injected and promptly disappeared! Several years later the verticals were re-examined and a 1m thick steam thief (lower *So*, trace *Sg* bed) identified

A simple spreadsheet calculates *Rank*; much the same as SEM's Reservoir Annuals.

	So	*Por*	*L*	*Re*	*h*	*OIP*	*RF*	*Oil Accessed*
excellent	0.75	0.22	100	200	4	26400	0.40	10560
good	0.65	0.18	100	150	4	14040	0.25	3510
fair	0.5	0.14	100	75	3	3150	0.15	473
poor	0.4	0.10	100	50	3	1200	0.10	120
trace	0.2	0.07	100	25	2	140	0.05	7
Sum								**14670**

Database inputs come from the wellsite geological striplog, plus reasonable assumptions based on relative permeability theory and demonstrated productivity of horizontal wells.

So quantifies the term 'oil stain'. It has definite limits. Virgin Leduc reef is So~0.90, whereas minimum is in the So 0.2 range and immobile. Most pools entered by horizontal wells are previously depleted from vertical wells by ~0.10. Mud gas detectors quantitatively record the presence of hydrocarbons and I've never seen a spurious response so long as the equipment is working correctly. Just a 5-unit kick (roughly 0.05% combustible hydrocarbon) means proximity to 'pay'. Depleted pools respond in the 10-200 range (*So* 0.4-0.5). Non-depleted pools provide 200-2000 units (*So* 0.5-0.6). Above 1000 units gas ebullates at the shaker (*So* >0.7)! Oilstain is masked by massive coloration from ineffective minute pores, nil stain from flushed vuggy pores. Bulk florescence from trays filled by consecutive samples, vacuum dried then viewed in a dark room is a more reliable visual assessment.

Por quantifies *ROP* and visual cuttings estimate, supported by *Elog* and core analysis. Mississippian reservoirs are multimodal: vugs; molds; intercrystalline; bioturbated; earthy. Autodiggers are routine and Pason conveniently measures ROP in 0.2m increments. A mTVD-ROP log plotting 0.2m increments smoothed by a 3-point rolling mean duplicates a CNL/Den or a Sonic Elog. We tend to underestimate *Por*. It all depends on sampling scale. Vugs have a *Por* of 1.0! Plugs tend to be cut from best-preserved core and always underestimate. Whole core analysis invariably fails to flush fluids from minute pores, so also underestimates. I trust CNL/Den but even this underestimates when anhydrite is present.

L is from the strip log; each 10m increment ranked *e* (excellent) through ***b*** (**barren**).

Ranking Horizontal Wells

Robert J. MUNDAY April 1999
306-731-2176

Re can be quantified if facies is known, especially for conduits, shoals and bioturbation. The bit under rotation follows conduits for 100's metres. It's reasonable to laterally extend them an equal distance. Limits are set by interwell spacing. When horizontal wells are 400m apart, *Re* cannot exceed 200m! *Poor* ranks severely restrict Re, and this is exactly what actual production numbers (CUMOP) demonstrate. Only exception is thick (h>>5m) bioturbated beds where oil slowly oozes into the horizontal wellbore: declines are minimal (<0.20); WORs keep around 1.0. This facies approximates Butler's (1994) drainage model.

h limits are defined by offset Elogs, also by trajectory as it bounces off top and base of pay. Compressed scale Section plots (mVsecn-mSS) indicate *h* and structure.

RF is a best estimate within quantified limits. Vertical well *RF*s are provided in *SEM* Reservoir Annuals. Relative Permeability curves provide theoretical limits. It's not possible to recover oil when *So* <0.2. Also lower *So* (<0.40) will likely be accompanied by *WOR* in the 10 range which places severe time and volume restrictions on *RF*. Actual horizontal well productivity compute *RF* higher than would be expected for *Good-Excellent* reservoir, maybe >0.50, and are minimal for *Fair-Poor* reservoir (~0.10) unless production goes into a long watery decline, only economic if the battery can handle a *WOR*.>10.

Summing ranking data over the length of a horizontal wellbore provides an expectation of how much oil the well will produce. Actual decline curves demonstrate at least 50% this oil will be produced in the first 24 months (CUMOP-24).
Excellent: CUMOP-24 >25,000, CAPEX payback <<1year, company builder, $10/bbl Oil.
Good: CUMOP-24 >10,000, CAPEX payback ~1year, ongoing net revenues, solid investment, room for land/asset purchase, $12/bbl
Fair: CUMOP-24 <10,000, CAPEX payback over ~3 years, pays it's way, $15/bbl.
Poor: CUMOP-24<5,000 CAPEX might not be recovered, questionable if economic at any oil price (higher oil price, more for land, drilling, completion, royalty overrides etc).
Barren: CUMOP-24 essentially zero.
How can this academic exercise in 'ranking' be transferred to the hectic environment of drilling a horizontal well?

Drilling into **'drainage conduits'** is the key to *Good-Excellent* ranking. Conduits are the Elog responses where Dt kicks offscale to the left. Core is seldom recovered and even less analyzed but *Por* values of >0.35 show up in assay sheets. Conduits are exposed in Mississippian outcrops at the Kananaskis (Alberta). Pioneering work by Friedman and Sanders (1978) on sabkha environments in Abu-Dhabi provides us with a reasonable picture of Mississippian age Saskatchewan-Manitoba carbonate facies and their lateral extents. Detailed local studies are documented in numerous publications of the *SEM*, the Saskatchewan Geological Society, plus academic journals. **Pisolites** mean a specific *Por*>0.25 facies with limited lateral extent (? an *SU*), possibility of a central bed of loose carbonate sand. **Bioturbated fecal-pellet micrite** means *Por*>0.15 facies extending >1000m, spotty dolomite recrystallization providing short (<25m) permeability conduits. **Open conduits** *(Por*>>0.25, *Kh* ?darcies) accompany cherty hardgrounds, presumably this is where groundwater moved. Sequence stratigraphy dictates that

facies (conduits) clinoform, which direction depends upon how the horizontal leg transects a lobe.

Pentium computers and **Command Shacks** encourage geology, engineering and directional drilling to communicate. "What happened?", "when", and "why" is better documented; decision-making improves. Just plotting trajectory from survey calculations allows projections 'ahead' of the bit, rather than recording where it's been. Spurious trajectory responses (when the *DHM* does not perform as *set*) most likely reflect internal facies variations.

How does 'Ranking' apply to the four examples?

1) **Re-entry:** mass balance indicates Leg #1's production inadequately drained OIP. Did Leg #1 access conduits? The re-drill was designed to access conduits, not move into an undrained SU. This strategy worked. It appears the Marly 'A' is still undrained (depending on how much a person believes oil drains downwards) but accessing by means of yet another upwards sidetrack outside the royalty window is non-economic.

2) **Sidetrack:** Leg #1's oscillating trajectory was not just a result of following seismic prognosis. First 100m from the shoe were drilled under rotation surveying every 3rd connection in belief the shoe angle was <90; pressure was on to move the rig to another location. Trajectory was actually >90 in the lowermost barren 'finger'. It took a severe downset to cut the underlying chert, which ultimately caused gyrations. Leg #1 accessed 455m *Fair*, 66m *Good* reservoir but there appeared to be a continuous bed of *Excellent* at the very top of the Midale 'A'. The sidetrack (Leg #2) accessed this bed for 250m *Excellent*. Without a rapid well site assessment of potential reservoir quality and trajectory required to access it, Leg #2 would never have been drilled and the investment would have a CUMOP in the <10000 range, as compared to its >20000 with Leg #2.

3) **Keep on drilling:** 18 days drilling to a junior TSE company is a major investment, especially when accessed reservoir is only 270m *Fair*, 165m *Good* which might have provided a 5000 CUMOP, inadequate to payback drilling costs. Continuing Leg #3 added another 5000 CUMOP providing a neutral NPV at prevailing oil prices. Decision to drill on was made from mudgas detector response. Trajectory was cutting through pisolite 'shoals', shallow marine carbonate gravel banks probably just a few 100m across. Gas response is faster and more precise than cuttings. A decision based on cuttings alone would have been to terminate.

4) **Evaluate all the information:** over $2million was lost in steam and the pilot fatally flawed. It was 6 years before the key cored interval from the observation well was examined. The box looked undisturbed; I doubt if it had been previously examined. Give away evidence was 'necking', the boudinage phenomena (Figure #7). Less competent water sand had never been recovered, all that remained were 'sausage ends'. Elogs reveal a lower *Rt*, not enough to flag caution but enough to back-calculate a low enough *So* (bitumen) to allow ingress of steam (*Sg*). This is where Schlumberger manuals, Archie coefficient and relative permeability curve theory are applied. CNL/Den was not run. The project ranks *Trace*, which is exactly how much bitumen was recovered!

ILLUSTRATIONS

GLOSSARY and SOURCES

Build	Wellbore as it changes from vertical to horizontal
CAPEX	**Cap**ital **Ex**penditure
CUMOP	**Cum**ulative **O**il **P**roduction
DHM	**D**own **H**ole **M**otor
Dt	**D**elta **t**ime
Elog	**E**lectric borehole **log**ging device
h	Reservoir **h**eight (thickness)
Kh	Permeability **h**orizontal
L	**L**ength of portion of horizontal wellbore
mTVD	**T**rue **V**ertical **D**epth in **m**eters
NPV	**N**et **P**resent **V**alue
Por	**Por**osity
RATE	Annual Interest **Rate**
Re	**R**adius **e**ffective of drainage
RF	**R**ecovery **F**actor
ROP	**R**ate **o**f **P**enetration
SEM	**S**askatchewan **E**nergy & **M**ines
Set	Orient DHM to change angle
Sg	**S**aturation **G**as
So	**S**aturation **O**il
WOR	**W**ater **O**il **R**atio

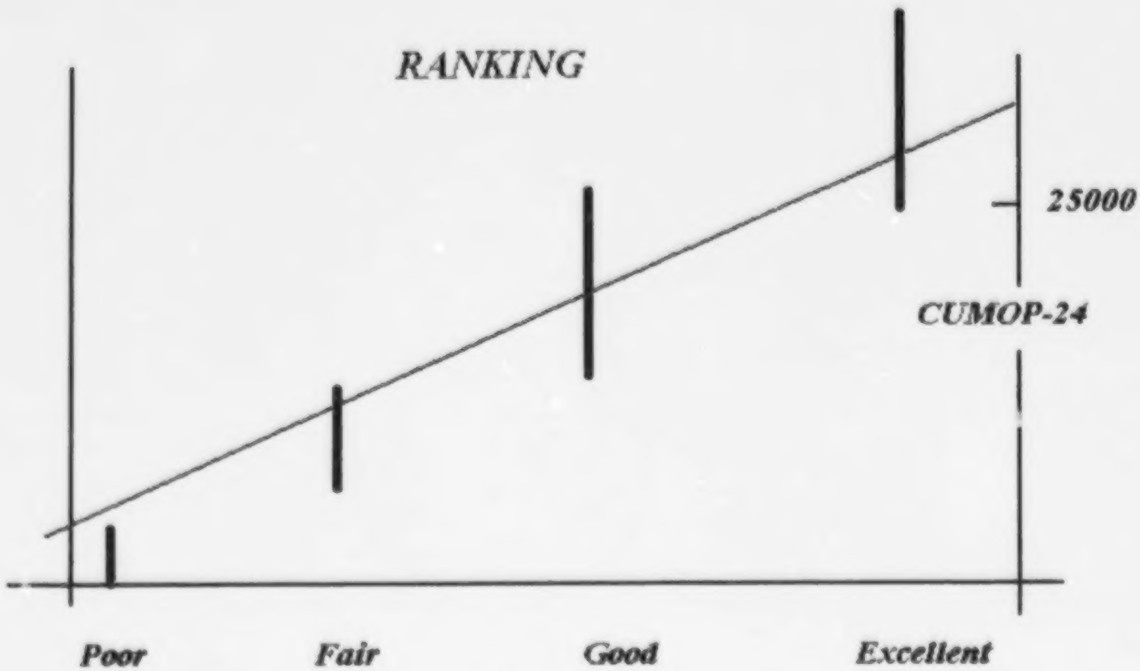
Butler, Roger M. 1995: Horizontal Wells for the Recovery of Oil, Gas and Bitumen; J.Petroleum Society of CIM.

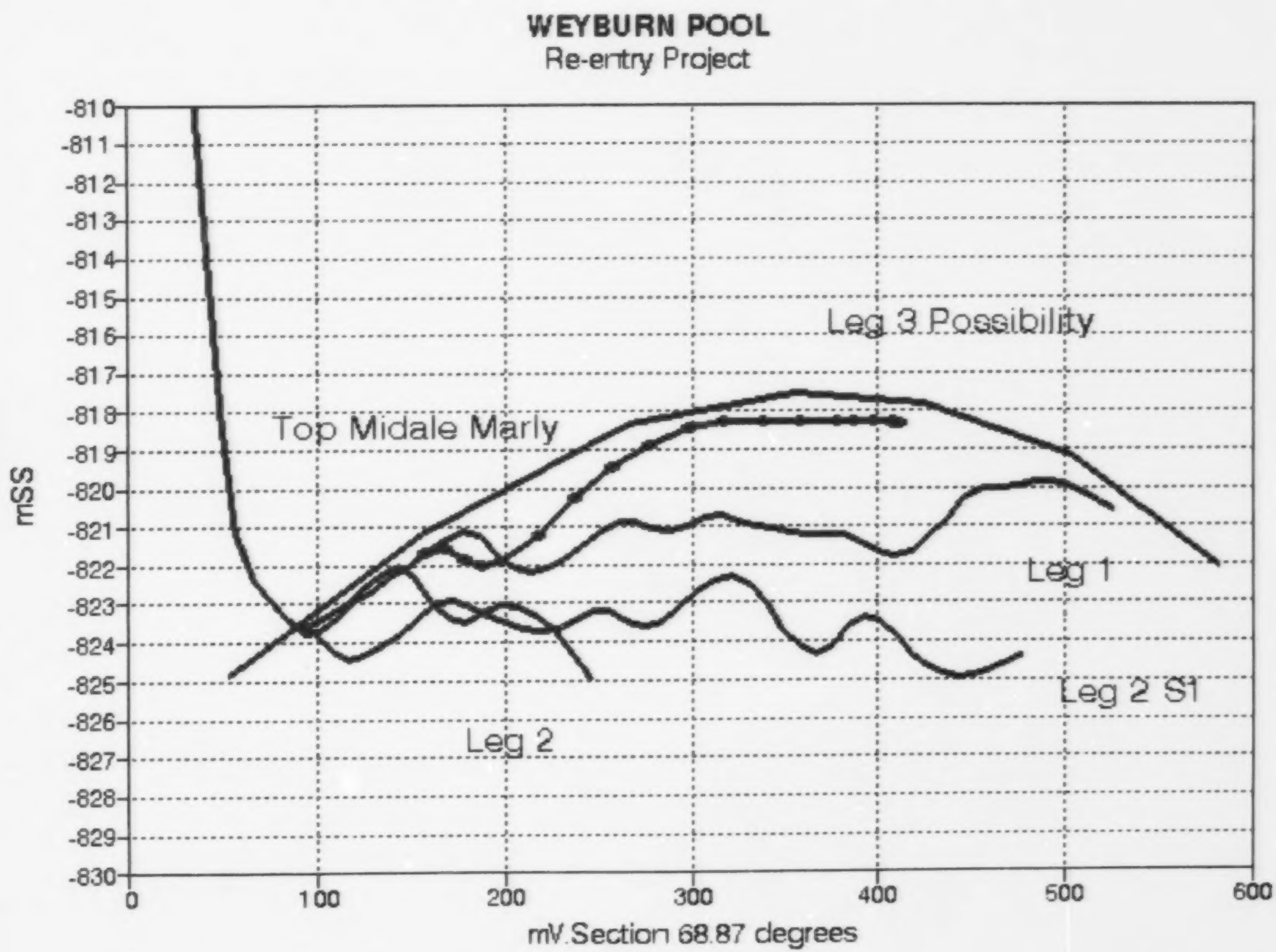
Dake L.,. 1978: Fundamentals of Reservoir Engineering; Elsevier.

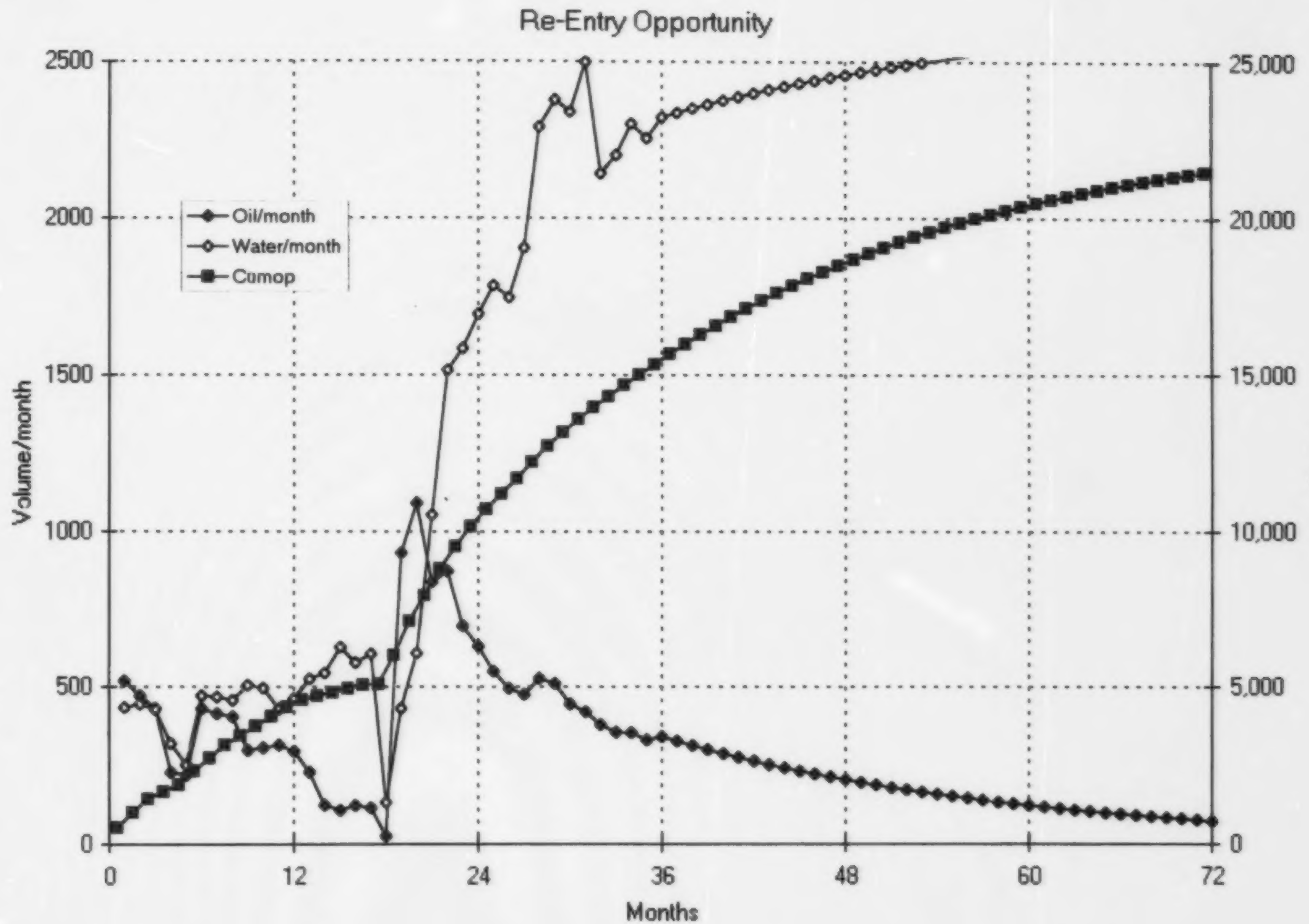
Friedman G. & Sanders, J. 1978: Principles of Sedimentology; John Wiley & Sons.

Saskatchewan Energy & Mines: Reservoir Annual, Well Files.

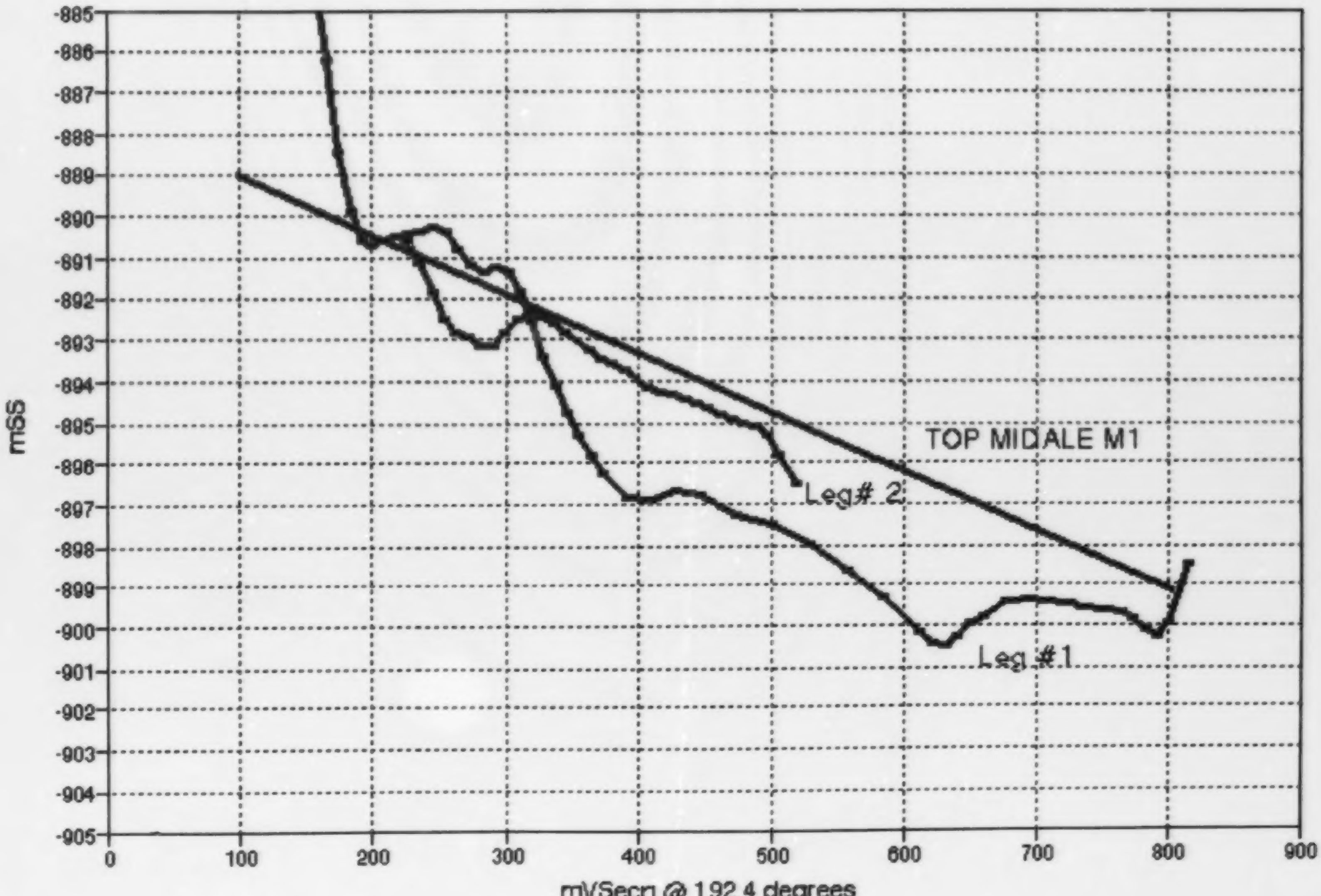
Schlumberger 1986: Log Interpretation Charts.


RANKING
25000
CUMOP-24
Poor
Fair
Good
Excellent

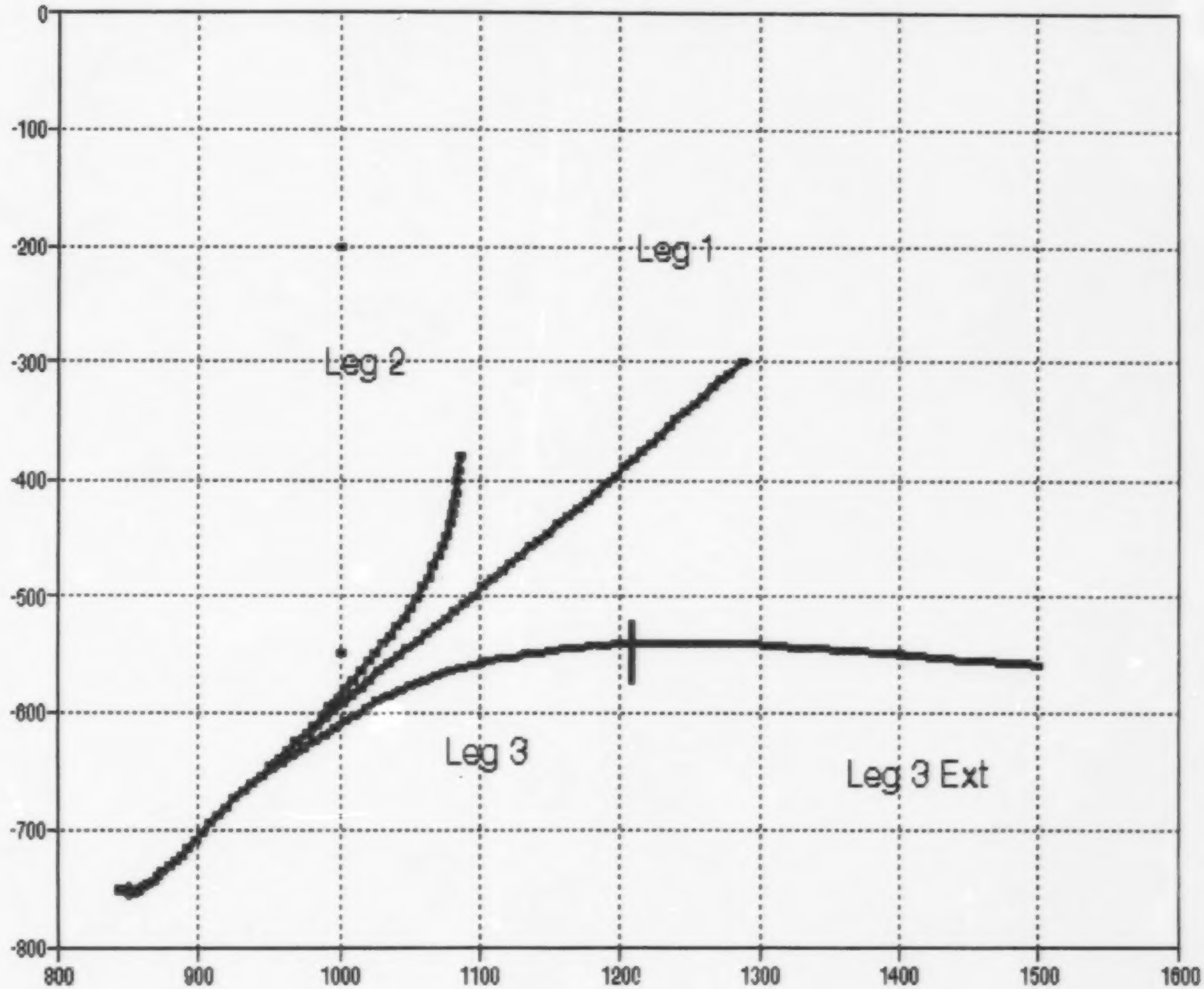

WEYBURN POOL
Re-entry Project
mSS
-810
-811
-812
-813
-814
-815
-816
-817
-818
-819
-820
-821
-822
-823
-824
-825
-826
-827
-828
-829
-830
0
100
200
300
400
500
600
mV.Section 68.87 degrees
Leg 3 Possibility
Top Midale Marly
Leg 1
Leg 2 S1
Leg 2


Re-Entry Opportunity
Oil/month
Water/month
Cumop
Volume/month
Cumop
Months
0
12
24
36
48
60
72
0
500
1000
1500
2000
2500
0
5,000
10,000
15,000
20,000
25,000

SIDETRACK INTO BETTER 'PAY'
MIDALE MARLY RESERVOIR

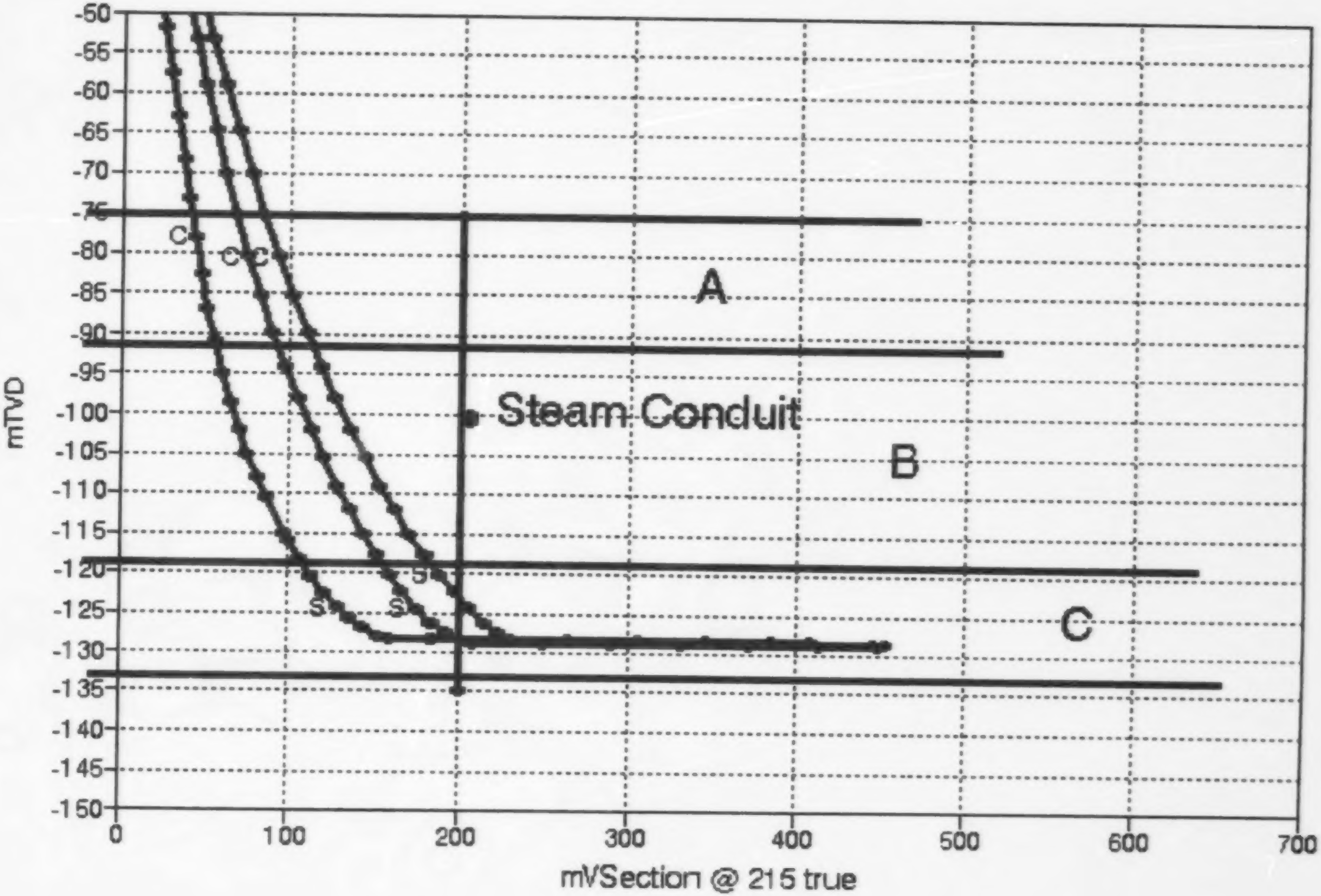


DRILL ON
Alida Member Pisolitic Shoals

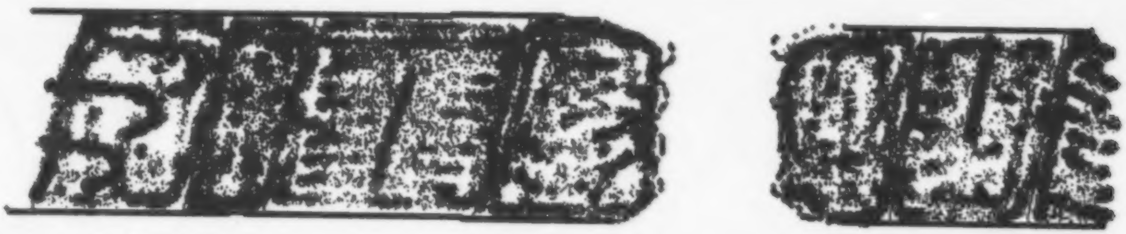


Evaluate All Information

McMurray Pilot, Steam Conduit



MISSING CORE



1 METER CORE BOUDINAGED OUT, SAUSAGE ENDS REMAINING
INCOMPETENT, LOWER So, SAND
?DEPLETED GAS SAND?
STEAM THIEF

Exploration Drilling on the Hume Structure: A Possible Astrobleme?

Mike Ware, Mario Ceccanese and Lawrence Bernstein Talisman Energy Inc.
7th International Williston Basin Horizontal Well Workshop, Regina SK. April 99

The recently discovered Hume structure is producing about 150 m3/d (950 bbl/d) of medium-gravity crude from the Red River Yeoman Formation. It's striking circular morphology suggests an extraterrestrial origin.

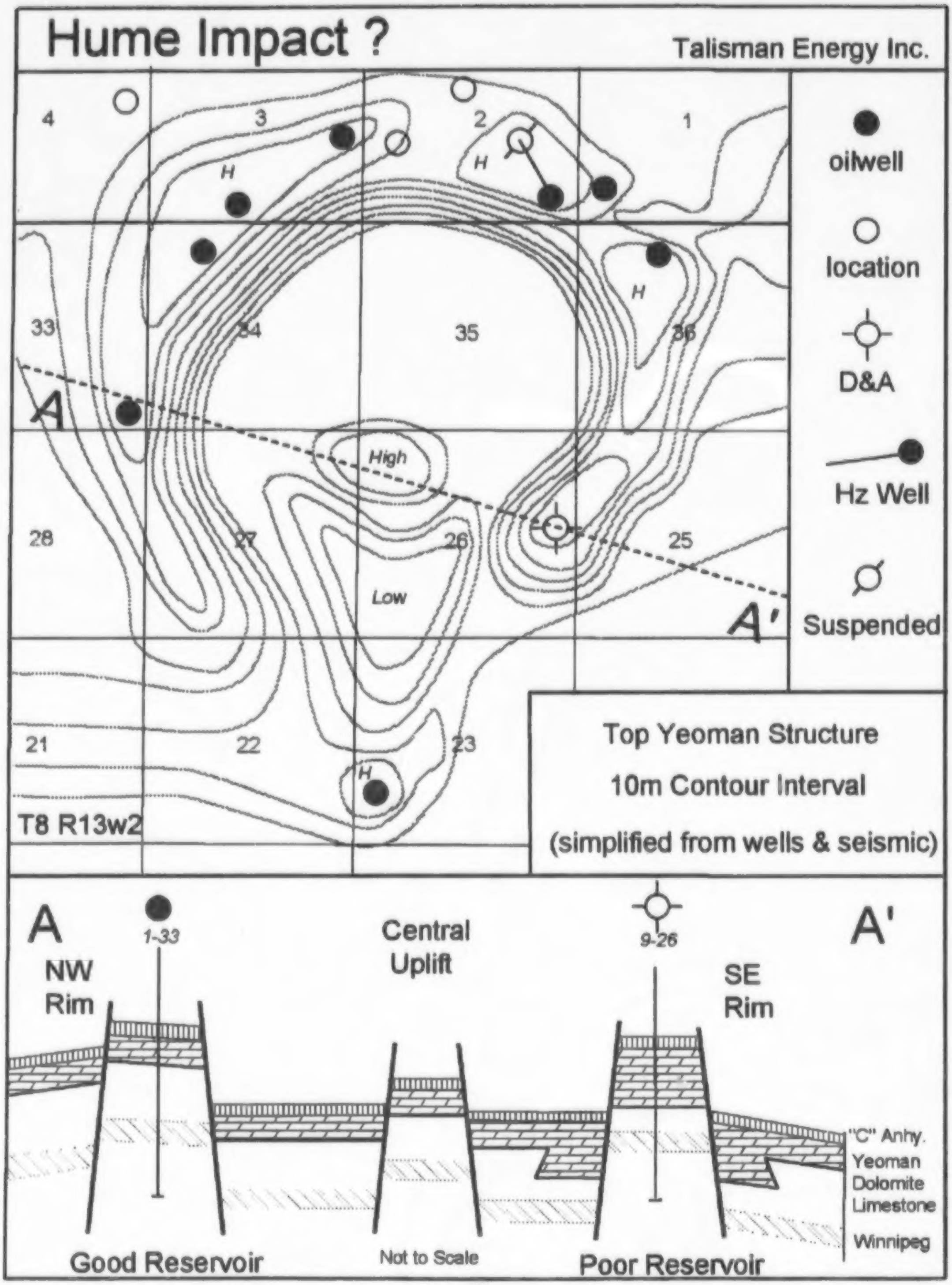
Location:
SE Saskatchewan, north flank of the Williston Basin, T 8-9, R 13w2. 13 km (8 miles) E of Weyburn, 27 km (17 miles) NW of Midale Red River Pool.

Observations:
Horseshoe shaped, 4 km (2.5 miles) in diameter, with well-developed 20m (60ft) high central uplift and up to 80 m (260 ft) of basement relief from rim to crater floor. The classic astrobleme morphology has been modified by subsequent erosion and faulting. A Proterozoic impact age is inferred from the normal layer cake geometry of overlying Cambro-Ordovician strata. If basement samples from the central uplift show high-pressure shock textures proving an impact origin, then Hume is another example of an oil producing Williston Basin astrobleme.

Red River Reservoir:
A complex diagenetic overprint controls Yeoman dolomitization and porosity within the Hume reservoir. It is impossible to predict production rates and reserves from wellbore parameters alone. Fracturing enhances permeability. Generally wells on the northeast and east side have a thicker section of Yeoman dolomite, which overall tends to be tighter and often contains a heavy dead oil stain, suggesting a seal failure. In southern and northwestern wells the Yeoman is typically interbedded porous dolomite and tight limestone. Seismic attribute analysis is being used to map reservoir character.

Production and Reserves
To date there are seven Red River wells (six vt. & one hz.) producing oil from the structure. The three wells on the northwestern rim have excellent initial rates, low water cuts, shallow decline rates and should each produce at least 50,000m3 (300,000bbl). Unfortunately wells on the northeast and east side are in poor reservoir and unlikely to be economic. Current drilling has proven up about 300,000m3(2 million bbls) of oil reserves.

Geological History of the Hume Structure (assuming an impact origin):
1. Compound crater formed in the Proterozoic, subjected to extensive terrestrial erosion (pre-Deadwood time) which removed the crater's southern rim.
2. Cambrian Deadwood succession completely infills remaining topography.
3. Overlying Winnipeg and Red River strata deposited on an relatively flat platform.
4. Thinning of the Silurian to Yeoman isopach implies pre-Devonian reactivation of the crater's circular fault system to form the present-day Red River structure.
5. Devonian Winnipegosis carbonates capitalize on this relief to create an arcuate band of atoll-like reefs.



Hume Impact ?
Talisman Energy Inc.
4
3
2
1
H
H
H
33
34
35
36
A
High
28
27
26
25
Low
A'
21
22
23
H
T8 R13w2
oilwell
location
D&A
Hz Well
Suspended
Top Yeoman Structure
10m Contour Interval
(simplified from wells & seismic)
A
1-33
Central
Uplift
9-26
A'
NW
Rim
SE
Rim
"C" Anhy.
Yeoman
Dolomite
Limestone
Winnipeg
Good Reservoir
Not to Scale
Poor Reservoir

Geosteering

Wayne Freisatz

SUNBURST CONSULTING
A GEOLOGY SERVICE

Geosteering is a general term for the collection and interpretation of geologic, engineering and directional data, to maximize exposure to a target horizon. The principal components necessary for successful geosteering are:

1) A well formulated and documented plan.
2) The gathering and synthesis of drilling data.
3) Timely communication of the raw and interpreted data.
4) Making appropriate adjustments to drilling parameters using the data and interpretations.
5) A post-well review and evaluation.
6) Geosteering should be a cooperative interdisciplinary effort, involving all of the participants associated with the drilling of a deviated or horizontal well.

Geosteering ?

- What is it ?
- Why is it important ?
- Who does it ?
- Who should be interested ?

1) Geosteering is the evaluation of all available geologic and engineering data to aid in the directional guidance of deviated or horizontal well bores to and within their designated targets.

2) Optimum geosteering of the well path directly impacts the ultimate economic success of the project by maximizing contact with the target reservoir and minimizing operating costs.

3) Geosteering is accomplished by the cooperative efforts of the representative(s) of the operator, the directional drillers, the MWD company, the on-site geologic team, and all other well-site contractors.

4) Those directly or indirectly benefited by successful geosteering are: the operator and its financial partners, on-site consultants and service companies, mineral owners and governmental entities, and the oil & gas exploration industry in general.

Pre-Well Preparation

- State the desired objective(s)
- Create engineering & geologic plan
- Documentation & Data distribution
- Pre-spud meeting and/or conference call

1) Someone once said "Proper planning prevents poor performance". In the case of a horizontal well, the expected geologic and engineering goals need to be clearly stated.

2) The step by step plan to achieve the stated goals should be formulated by the operator, with the advice and input of the consultants, and service companies.

3) A written well plan should be distributed to all concerned parties as part of a comprehensive "well packet". It should include:

   a. prognosis & operations plan, with diagrams

   b. plat map & legal setback requirements

   c. offset well data & log excerpts

   d. data distribution & contact list

   e. structure / stratigraphic map of prospect area

4) A pre-spud or pre-kick-off conference call or meeting should be planned to discuss the specific objectives of the project and iron out operational details. This event will familiarize the "team" with the project and each other.

During Drilling

- Communicate objectives & plan to all concerned parties
- Gather appropriate data & evaluate
- Distribute progress reports
- Interpret all data & make targeting adjustments
- Communicate proposed adjustments & seek input from all concerned parties

1) Make sure everyone involved knows the plan, and understands their part in it. Try not to take anyone for granted. The more involved in the process people are, the less likely mistakes will occur.

2) Careful monitoring and recording of data while drilling is invaluable to the success of the project . The more data collected, the better the chance of optimizing the project and reproducing success. Some parameters helpful in geosteering include:

a) Lithology samples

b) Rate of penetration data & drilling parameters

c) MWD logs & directional surveys

d) Mud properties & volume changes

e) directional driller's input on drift tendencies

3) Move pertinent data around location and to the operator in a timely fashion. Information management is usually preferable to crisis management.

4) Discuss the well's progress regularly. Attempt to project the well bore trajectory and target dip ahead of the bit. Maximize the time drilling in the "pay".

5) If changes do become necessary, explanations are better than orders.

Where does the data come from and how reliable is it ?

- Lithology
- ROP & drilling parameters
- MWD data
- Directional surveys
- Mud properties & volumetrics
- Gas detection

1) Cuttings samples are a key part of the evaluation process of any well. In the case of horizontal drilling, recovery of good representative samples becomes more difficult with distance out into the lateral.

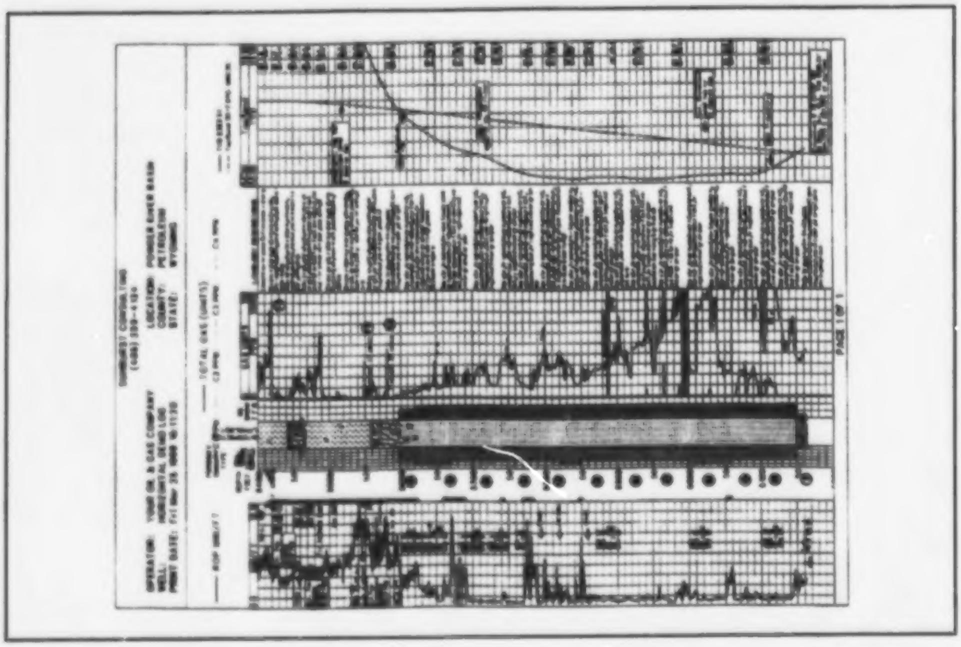
2) Drill rate information is helpful in evaluating changes in relative porosity, both vertically and horizontally. Mechanical factors should be taken into consideration when interpreting drill rate information.

3) The MWD data, including directional surveys and logs, are important to projecting the spatial location and stratigraphic position of the well path.

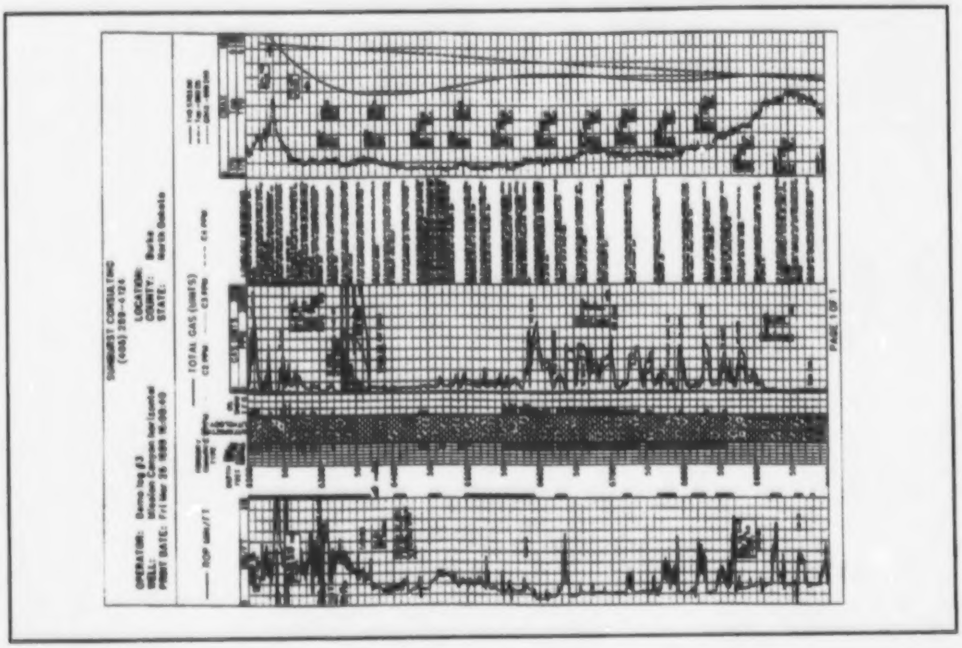
4) Directional survey information can also be gathered from wireline steering tools during times when MWD data is not available or useable.

5) Relative changes in drilling fluid properties and volumes can be useful in evaluating reservoir characteristics, including lateral variability and fluid production potential.

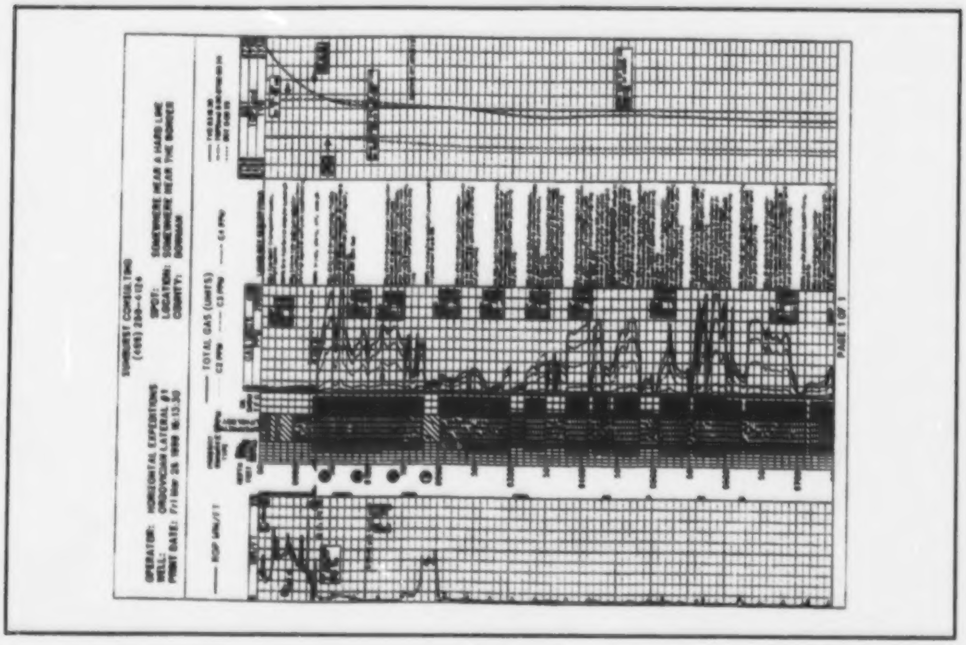
6) Total-gas readings and chromatography can both be used to "fingerprint" targets and help to differentiate gas/oil/water contacts within the reservoir.



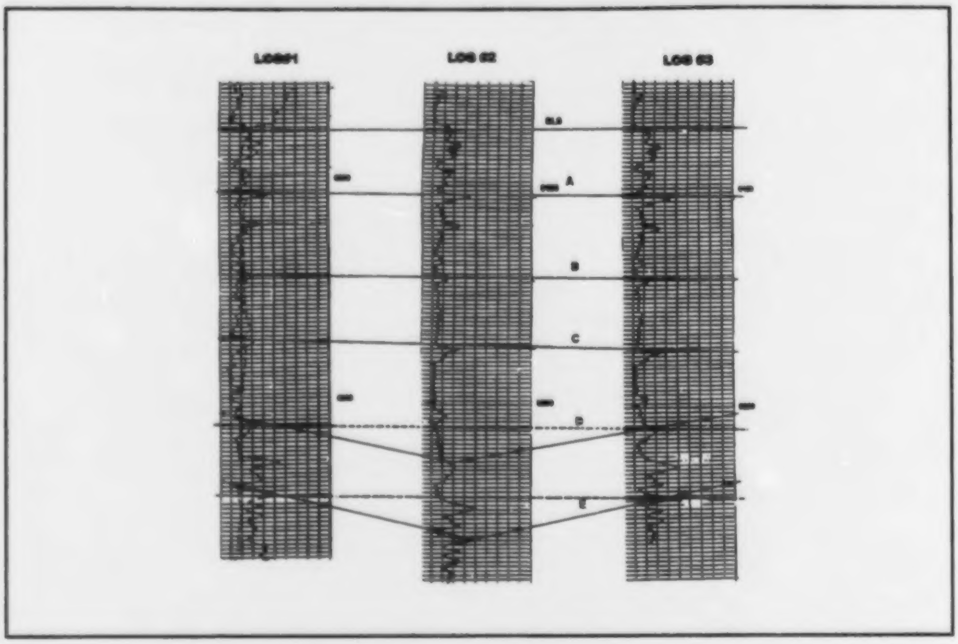
This slide depicts a geosteering log. Note the use of the TVD [True Vertical Depth] plot along the top portion of the illustration. This type of plot can be very useful in visualizing the effects of dipping targets on the horizontal well bore. Although somewhat complex, summary plots such as this can help to synthesize many wide-ranging data sets.



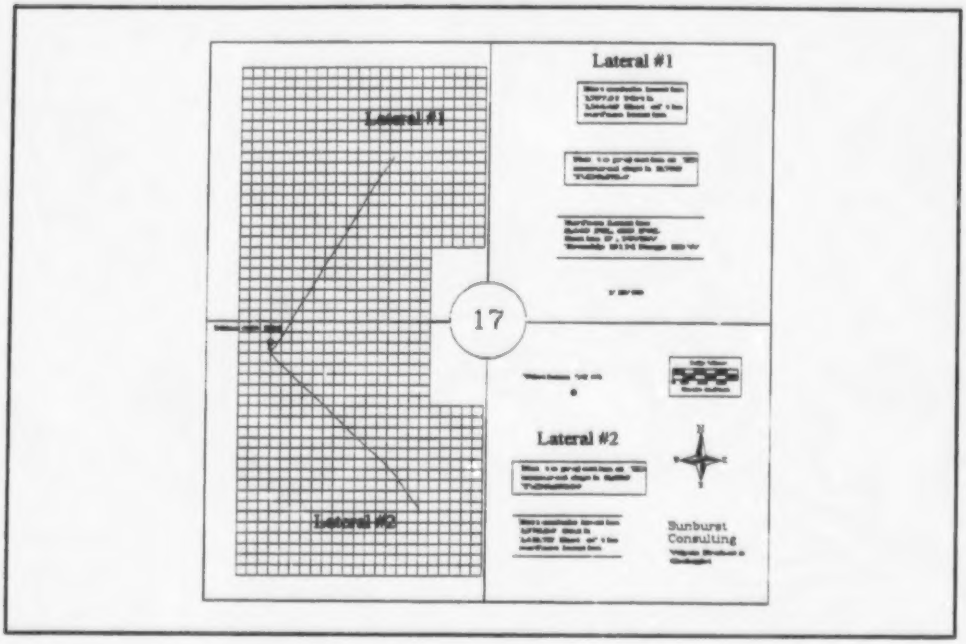
This example includes the use of a MWD gamma-ray curve for steering control. Gamma-ray data can be particularly useful for steering when high contrast lithology changes do not bound the target horizon.



Here we see a geosteering plot with depiction of a target "window" and somewhat variable dip rates. Note the high contrast in the drill rate curve between target and non-target lithologies. This example also shows lateral variations in the target, as highlighted by sample changes and gas signatures.



In the gamma-ray log cross section above we see the utility of gamma-ray curve correlations for geosteering purposes. Note the correlation between the arbitrary gamma markers ["A" through "E"] in the offset well [Log #1] and the TVD log from the curve-build section of a horizontal well [Log #3]. Log #2 is actually derived from the same gamma-ray data as Log #3, but with one incorrect survey data point inserted!



This plot is used to portray the map view progress of horizontal laterals. This type of plot can also be helpful when confronted with hard-line restrictions.

Dip Estimation

- One marker in a nearby offset well or vertical pilot hole & a subsequent marker in the lateral.
- Encounter equivalent stratigraphic markers more than once in a lateral.

The use of equivalent stratigraphic markers, either lithologic or gamma-ray, can be employed to refine target dip estimations. These short term or local dip variations, taken together with regional or field maps, are incorporated into the geosteering process.

Apparent dip (θ_a) may be calculated by employing the true vertical depths (TVD) at the set of equivalent entry points and the map view distance between them:

$$\tan\theta = \text{Rise} / \text{Run} \qquad \text{or} \qquad \theta = \tan^{-1}(\text{Rise} / \text{Run})$$

$$\theta_a = \tan^{-1}(\text{TVD difference/Map view difference})$$

True dip (θ) may be calculated if the dip direction is known:

$$\theta = \tan^{-1}(\tan\theta_a / \cos(\text{True dip direction} - \text{Hole direction}))$$

or for formation dip less than 20° can be approximated by the simplified form:

$$\theta \approx \theta_a / \cos(\text{True dip direction} - \text{Hole direction})$$

It is useful to keep in mind that the previous methods are actually showing apparent dip rather than true dip. Therefore, changes in the lateral direction (or azimuth) may result in changes in the apparent dip rate.

Apparent dip

To calculate the apparent dip in a direction other than the true dip direction. [Note that apparent dip is always less than true dip.]:

Where θ = True dip angle, θ_a = Apparent dip angle,
∂' = Borehole direction, and Ψ = True dip direction

$$\theta_a = \mathrm{Tan}^{-1}\left(\mathrm{Cos}\,(\Psi - \partial') * \mathrm{Tan}\,\theta\right)$$

For dip angles less than 20° the calculation may be approximated by:

$$\theta_a = \mathrm{Cos}\,(\Psi - \partial') * \theta$$

True Vertical Thickness

For the True Vertical Thickness (TVT) in a deviated borehole intersecting a dipping bed:

Where ΔD = Measured depth in the bed, λ = Borehole angle,
$\partial = \partial' + 180°$

$$TVT = \frac{\Delta D * \mathrm{Cos}\left(\mathrm{Tan}^{-1}\left(\mathrm{Cos}\,(\Psi - \partial) * \mathrm{Tan}\,\theta\right) - \lambda\right)}{\mathrm{Cos}\left(\mathrm{Tan}^{-1}\left(\mathrm{Cos}\,(\Psi - \partial) * \mathrm{Tan}\,\theta\right)\right)}$$

True Bed Thickness

Given the TVT and formation dip angle (θ) a true bed thickness (TBT) may be calculated by:

$$TBT = \mathrm{Cos}\,(\theta) * TVT$$

Here are a couple of additional formulas useful in sorting out the geometric relationships between apparent dip, true dip and bed thickness.

Holt, O.R., Schoonover, L.G., and Wichmann, P.A.: "True Vertical Depth, True Vertical Thickness, and True Stratigraphic Thickness Logs", Trans., SPWLA Logging Symposium (1977) paper Y

Post drilling analysis

- Collect records, reports & samples
- Post well meeting &/or conference call
- Analyze what worked & what didn't & why
- Re-draw or confirm maps & reservoir characterizations
- Incorporate new insights into future well plans

1) Once a well has finished drilling the tendency may be toward moving on to the next well or project. However, valuable information and insight may still be gained from a historical review of well data.

2) Timely discussions with the people involved in the drilling of the well may yield important ideas for improving future plans.

3) Try to work out the reasons behind any successes or failures that were encountered.

4) Use the information gathered from the well to update the geologic and reservoir engineering understanding of the prospect.

5) Employ the lessons learned to maximize the potential for success on subsequent projects. Share these insights with co-workers and perhaps with the industry at large. Success is good for business!

Summary

- Make plan & communicate it
- Gather data, revise plan & communicate
- Communicate, summarize data & results
- Benefit from experience & communicate

Reservoirs in Winnipegosis Basin Laminites (Ratner Member), Williston Basin

Don L. Kissling, Jackalope Geological Ltd., Berthoud, CO
Art Slingsby, Richland Petroleum Corporation, Calgary, ALBA

From a Regional Viewpoint

The Middle Devonian Winnipegosis Formation is formed of a procession of mostly carbonate depositional facies that had accumulated over time under broadly different physiographic and hydrographic environments and, consequently, is host to a wide spectrum of oil-producing reservoirs. These facies define an intracratonic platform and basin complex (Elk Point Basin) that extended from northern Alberta to southeastern Saskatchewan and western North Dakota where the southern apex of regional Winnipegosis accumulation overlaps the present Williston Basin.

Here the Winnipegosis basin is surrounded by a suite of platform margin facies including progradational basin slope wedges surmounted in places by platform margin reefs, together ranging 45-65 m or 150-210′ thick (Figure 1). In turn, platform margins are surrounded by platform interior facies, including widespread mud-rich, stromatoporoid banks. These strata thin progressively to depositional zero edges passing through northeastern Montana and southwestern and north-central North Dakota. Within the basin the Winnipegosis (excluding pinnacle reefs) measures just 14-27 m or 45-90′ thick, thinning toward the basin axis. Numerous dolomitized pinnacle reefs north of the Brockton-Froid lineament typically measure 60 m or 200′ thick or less; whereas, the fewer, sparingly dolomitized pinnacle reefs in the more deeply foundered portion of the basin southeast of this lineament range 75-85 m or 240-280′ thick.

The numerous, prolific Winnipegosis oil pools in the western platform interior, extending as a NW-SE fairway from Fairview in east-central Montana to Minton in south-central Saskatchewan, are developed in dolomitized stromatoporoid bank and associated marine shelf facies, sealed above by thin, widespread anhydrites that form the top of the Winnipegosis in this region (Figure 1). Moraine Field, poised at the northern edge of the Brockton-Froid lineament, and Temple Field which has produced 5 MMbo from Winnipegosis basin slope facies sealed above by tight, undolomitized platform margin reefs, are situated on the western platform margin (Ehrets and Kissling, 1987). Within the basin regime pinnacle reefs and mound clusters, notably at Tableland, Hitchcock and Macoun in southeastern Saskatchewan, bear oil reservoirs in stromatoporoid-coral rim and proximal flank facies (Martindale et al, 1991). Far less known, however, are Winnipegosis reservoirs developed in dolomitized basin laminites of the Ratner Member.

Winnipegosis strata forming the vast basin floor consist of just two facies. The basal marine shelf facies, ranging 5-12 m or 15-40′ thick, which overly the shaly dolomite of the Ashern Formation. These strata consist of typically undolomitized, nodular-bedded wackestone and packstone generally rich in brachiopods, crinoids and Chondrites burrows (Figures 3, 5 and 6). Excluding pinnacle reefs, this facies represents the sole accumulation within the basin during deposition of the entire Winnipegosis over platform interiors, platform margins and basin slopes.

The overlying euxinic basin facies or Ratner Member invariably consists of finely laminated, organic-rich mudstone, ranging 5-18 m or 15-60′ thick, thinning toward the basin axis. It is conformably overlain by dense, laminated, enterolithic anhydrite forming the base of the Prairie Evaporite (Figures 3, 5 and 6). Jin and Bergman (1998) have shown that the Ratner Member is represented by three recognizable sedimentary cycles of which finely laminated mudstone is the principal component. Non-microbial fossils are confined to rare Chondrites and Planolites burrows and few minute crinoid columnals. The dark, micritic mudstone is particularly organic rich (Osadetz and Snowdon, 1995) and is a likely source rock for Winnipegosis oil. The euxinic basin facies, the youngest Winnipegosis sediments, accumulated during an episode of sea-level lowstand as evaporative drawdown led to subaerial exposure of surrounding platforms and pinnacle reef crests, density stratification of constricted basin waters, and eventually the onset of Prairie evaporite precipitation.

The bulk of the Ratner consists of tight limestone, while the upper 1-5 m of strata are dolomitized. Dolomitization and porosity generation in the upper Ratner may be owing to seepage reflux of Mg-rich brines from the overlying few metres of basal Prairie anhydrite. This condition is likely enhanced where the basin laminites onlap the lower basin slopes below platforms and the proximal flanks of pinnacles where the basal Prairie anhydrite (Whitkow Anhydrite) may thicken to as much as 27 m or 90′. Lenses of reservoir-quality porosity ranging up to 28% Ø have been observed in the upper Ratner throughout the southern Winnipegosis basin regime, and oil staining and small oil recoveries (where tested) are not uncommon. Dome Scurry Tableland 11-14-2-9W2, drilled in 1975, produced approximately 30 Mbo from basin laminites that onlap the southern proximal flank of Tableland pinnacle reefs. However, this reservoir likely communicates with oil-charged reef reservoir.

Stoneview Field

Until recently, Stoneview Field, located at the north end of the Nesson anticline in North Dakota, represented the sole commercial oil production from Winnipegosis basin laminites. Stoneview lies on a low-relief, south-southeast plunging structural nose on the east flank of the Nesson anticline and produces from five Mississippian, Devonian and Ordovician pays (Figure 2). This structure intersects a trend of greater Ratner dolomitization and porosity that extends in irregular fashion along the toe of the slope basinward from the western platform margin. Enhanced reservoir conditions along this trend may be a function of more extensive dolomitization

associated with vastly greater thicknesses of the basal Prairie anhydrite lying just west and upslope of the field.

Although minor structural closure does exist over the Stoneview Winnipegosis pool, northward sharp decline of upper Ratner dolomite accompanied by updip loss of porosity and permeability indicates that stratigraphic trapping is a companion mechanism. This is especially evident in the Stoneview structural cross section (Figure 3), in which 2.7 m or 9' of porous dolomite forming the upper Ratner at Home Kjelshus 1-25 passes to sparingly dolomitized, essentially tight limestone at Home Kjelshus 2-25, located less than one kilometre northwest. Oil recoveries were made on drill stem tests of Ratner porosity at two wells southeast of Stoneview Field (potential commercial production behind pipe) and from an abandoned well northwest of Stoneview (note "OIL REC" in Figure 2). These suggest that other oil-charged Ratner pools may exist as structural-stratigraphic traps.

Logs of the three wells that produce from upper Ratner dolomitized basin laminite, including Home Kjelshus 1-25, Hunt Ericson 1-A, and the discovery well, Hunt-Holte-BND 1, are also featured in Figure 3. Perhaps because of relatively low permeability, these three wells, having initial productions ranging 31 to 160 bopd, have proved only marginally economic, having produced somewhat more than 300 Mbo and 114 Mbw since 1972 for two wells and since 1980 for the third well.

Kingsford Winnipegosis Pool

Previous boreholes penetrating the Winnipegosis in the Kingsford area either had encountered pinnacle reefs measuring 60 m thick (at 15A-18-4-6W2 and 4D-1-4-7W2) or the proximal flanks of pinnacle reefs (at 12C-31-3-6W2 and 15-7-4-7W2). The much thinner basin laminites had not been drilled in the area. The Winnipegosis pool discovery well (Richland Northrock Kingsford 31/8-14-4-7W2), spudded in August 1997, targeted a seismic anomaly for Ordovician Red River potential. The Winnipegosis time structure map (Figure 4) shows a small but prominent structure with significant closure projecting southwest from Steelman.

The discovery well intersected 19 m of typical Winnipegosis basin facies, including 8 m of the Ratner Member, overlain by 2.7 m of basal Prairie anhydrite (Figure 5). The dolomitized upper half of the Ratner there displayed 1.5 m potential pay bearing an estimated 10-16% porosity. A drill stem test of this interval recovered 500 m of oil, 500 m of gas-cut and oil-cut water, and 128 m of gas-cut mud (Figure 5). As a further test, this zone was perforated and extended flow tested during early October 1997. Over a span of 67 hours the test recovered 186.5 m^3 oil (1173 bo) with 1% water cut, at a maximum rate of 77 m^3 oil/day (484 bopd). Analysis of the pressure build up suggested that, although the zone possessed high permeability, the well bore had a particularly high skin factor of 266. This oil is currently behind pipe and the well was completed in the Red River.

Encouraged by results of the discovery well, the operators spudded a nearby borehole (Richland Northrock Kingsford 41/8-14-4-7W2) in November 1997 and subsequently completed it in the upper Ratner Member for initial production of 111 m^3 oil/day (698 bopd) with just 1 m^3 water/day (6 bwpd). To March 1999 this well has produced 19,747 m^3 oil and 6949 m^3 water (124,210 bo and 43,710 bw). Here the Winnipegosis measures 18 m thick, the Ratner Member measures 7 m thick and the overlying basal Prairie anhydrite is 2.6 m thick (Figure 5). A core from 41/8-14-4-7W2 shows a greater proportion of the Ratner (the upper two-thirds) is dolomitized. Core analyses indicate that this relatively thick pay zone bears 14-22% intercrys-talline and moldic porosity and 3-45 md permeability (Figure 6). As elsewhere in the basin regime, dolomitized upper Ratner is underlain by tight, laminated, micritic mudstone forming the lower Ratner, in turn underlain by equally tight nodular-bedded skeletal wackestone comprising the lower Winnipegosis.

Conclusions

From these two producing examples, it may be concluded that hydrocarbon traps in Winnipegosis basin laminites may exist as relatively small, structural features defined by closure as at the Kingford Winnipegosis pool, or they may exist as larger structural-stratigraphic traps by virtue of porosity/permeability loss updip from a south-plunging nose as at Stoneview Field. The readily defined, typically well fractured pay zone, sandwiched between impermeable anhydrite and limestone, appears to be a logical candidate for horizontal well development. The potential of this pay zone has been largely ignored and inadequately explored. Because of the relative success of seismic identity and location of Winnipegosis pinnacle reefs in southeastern Saskatchewan, surprisingly few deep wells had penetrated the basin laminites prior to the recent Red River exploration programs.

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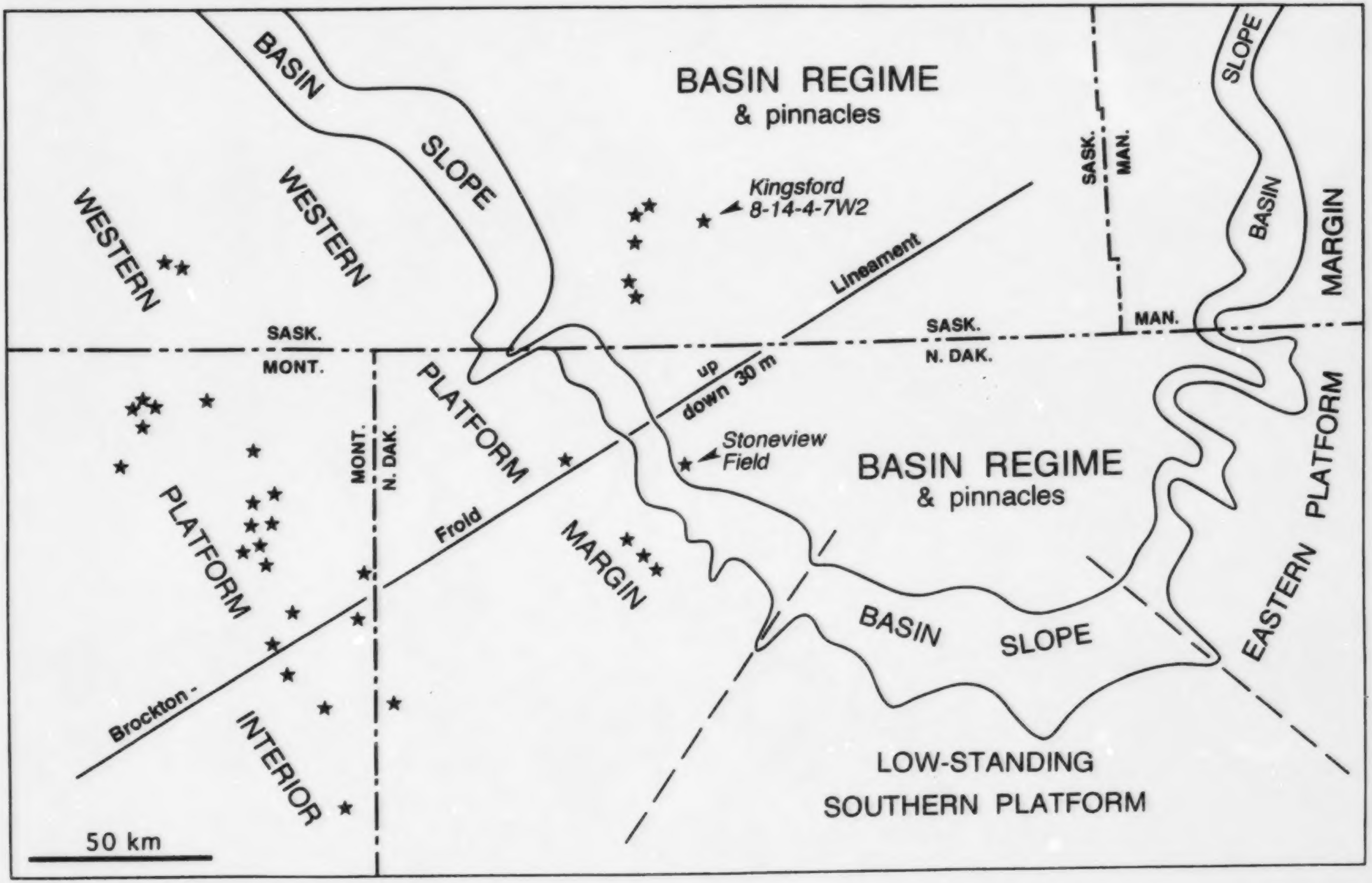


Figure 1 Location of Winnipegosis oil production within major physiographic and depositional regimes (Kissling & Slingsby, 1999).

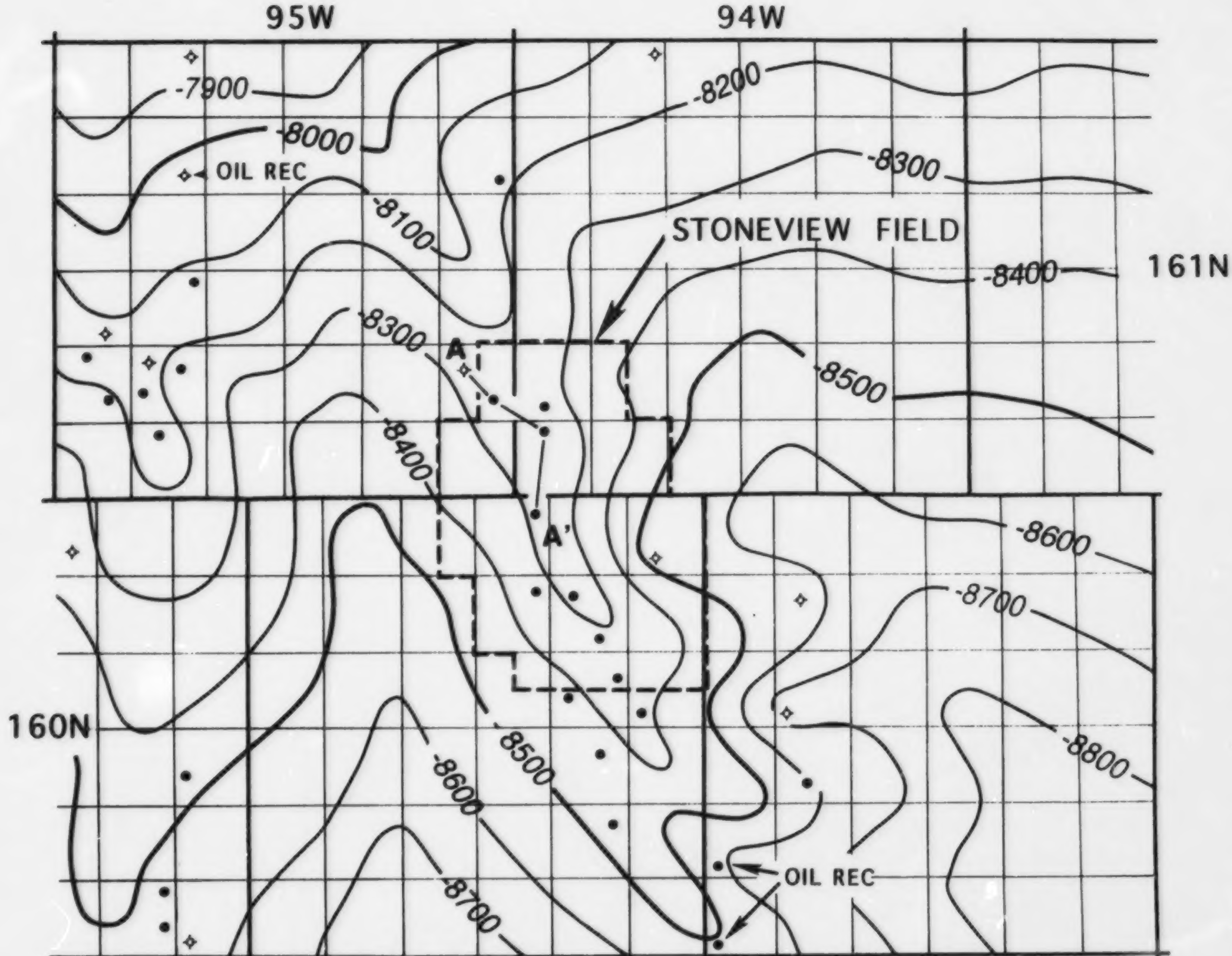


Figure 2 Structure on top of the Winnipegosis Formation at Stoneview Field, northeastern North Dakota (Kissling & Slingsby, 1999).

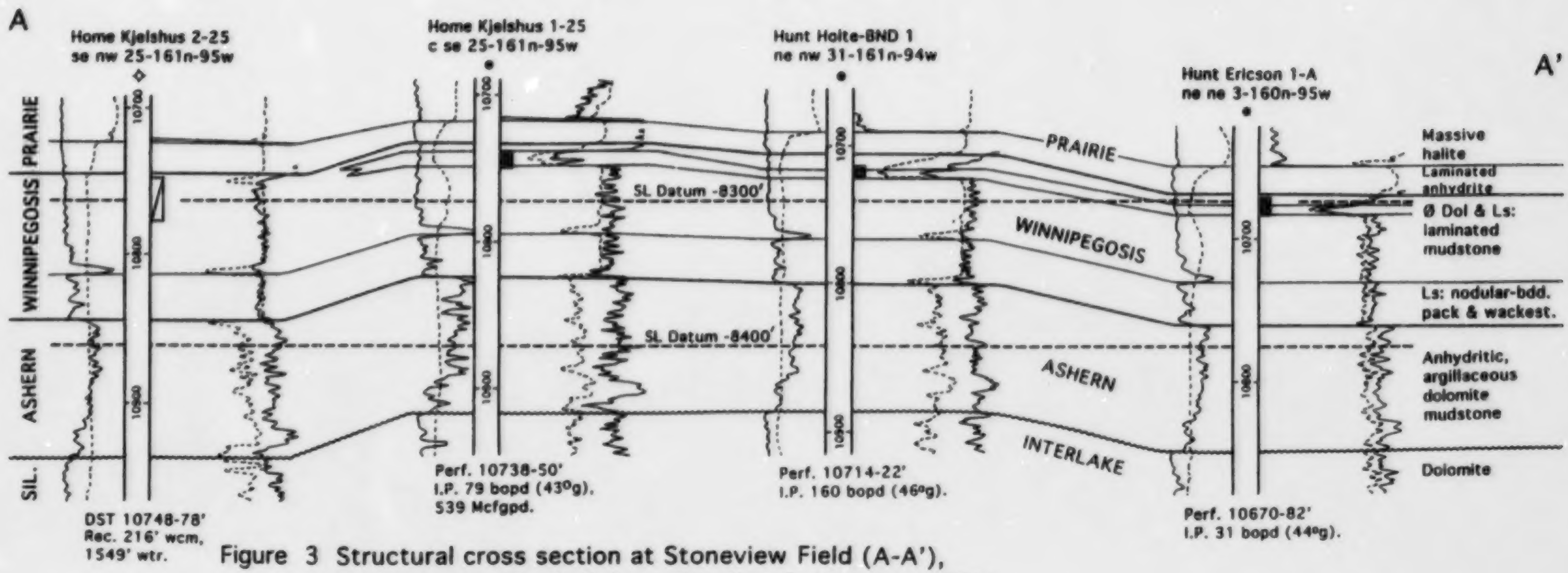


Figure 3 Structural cross section at Stoneview Field (A-A'), northwestern North Dakota (Kissling & Slingsby, 1999)

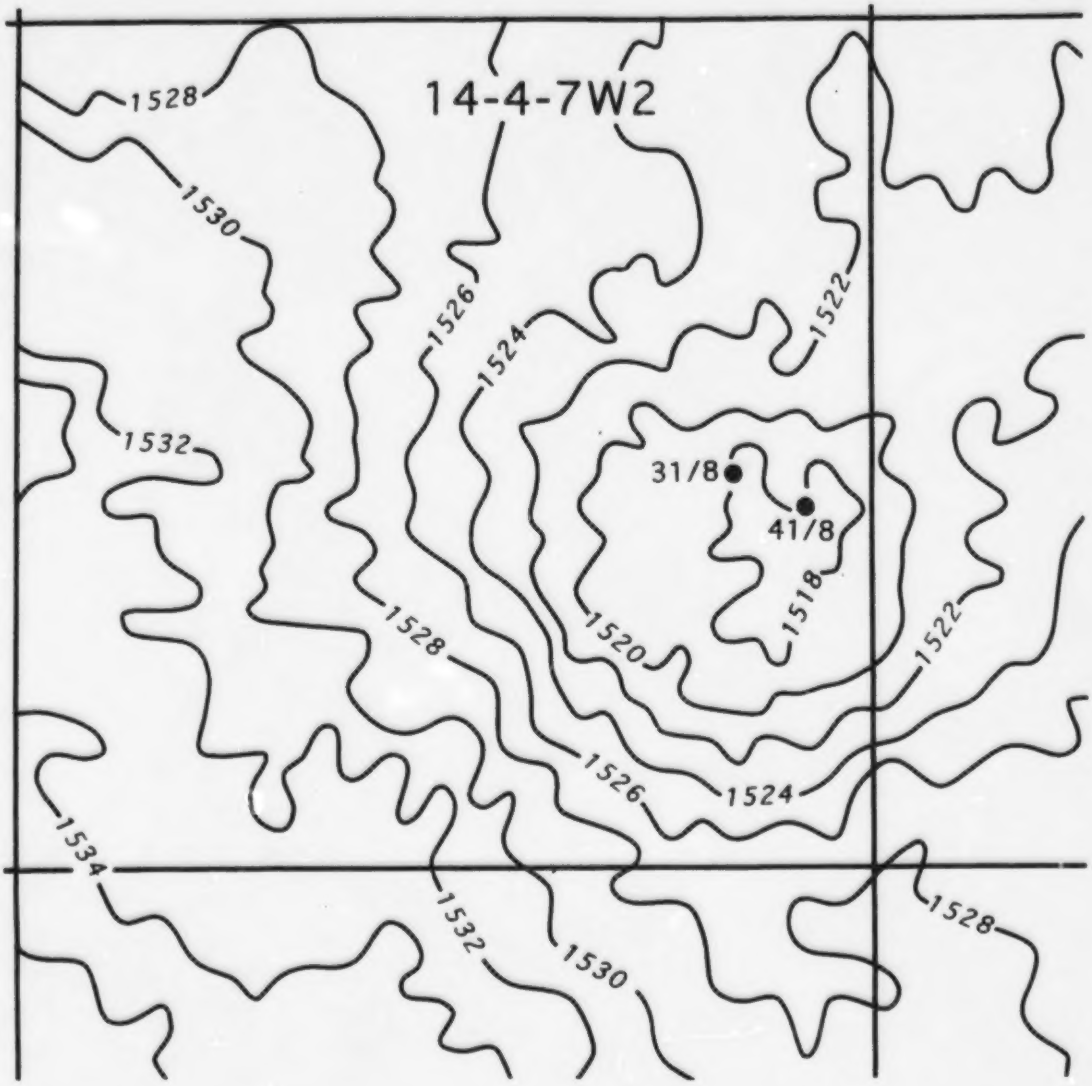


Figure 4 Winnipegosis time structure at Kingsford, Saskatchewan (Kissling & Slingsby, 1999)

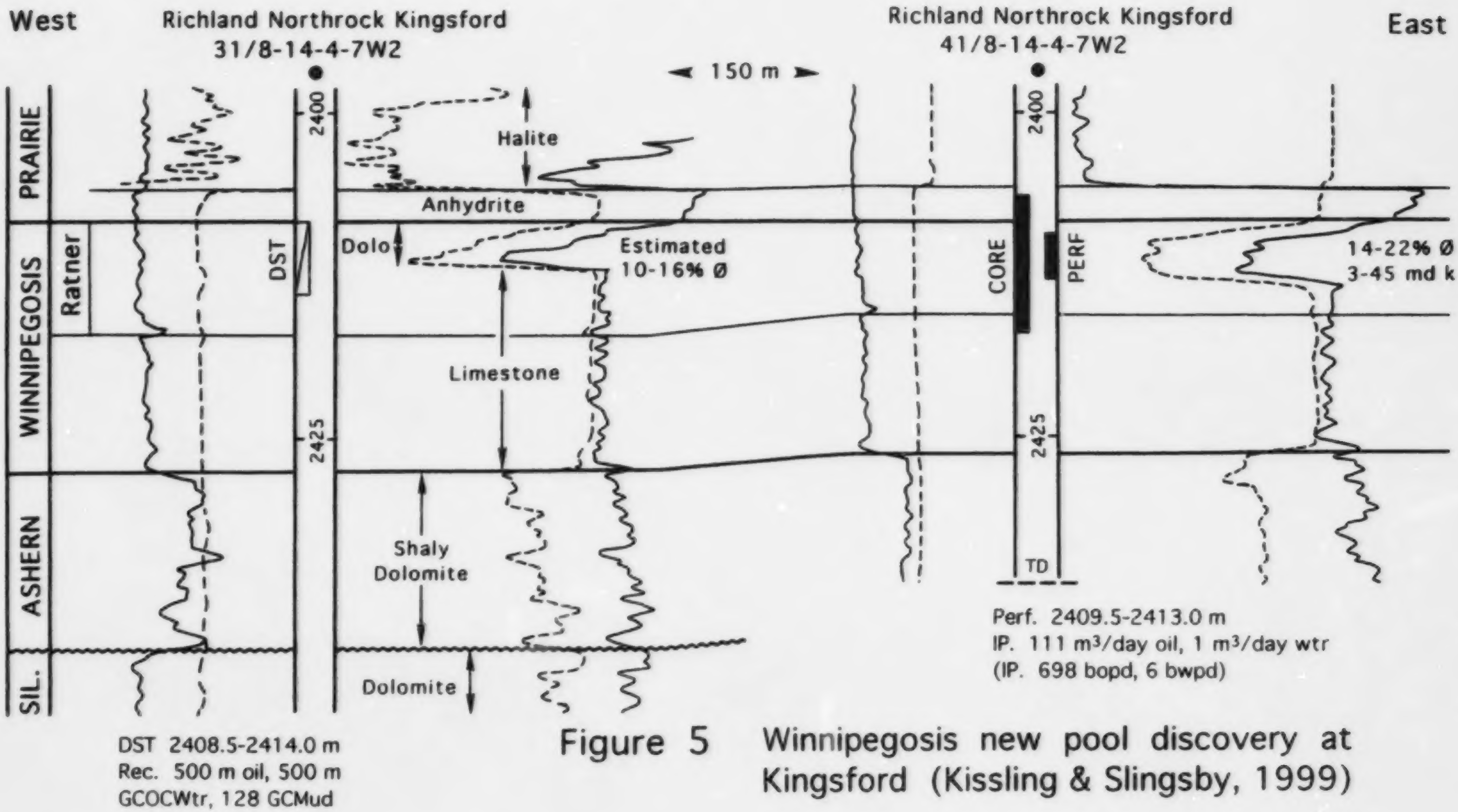
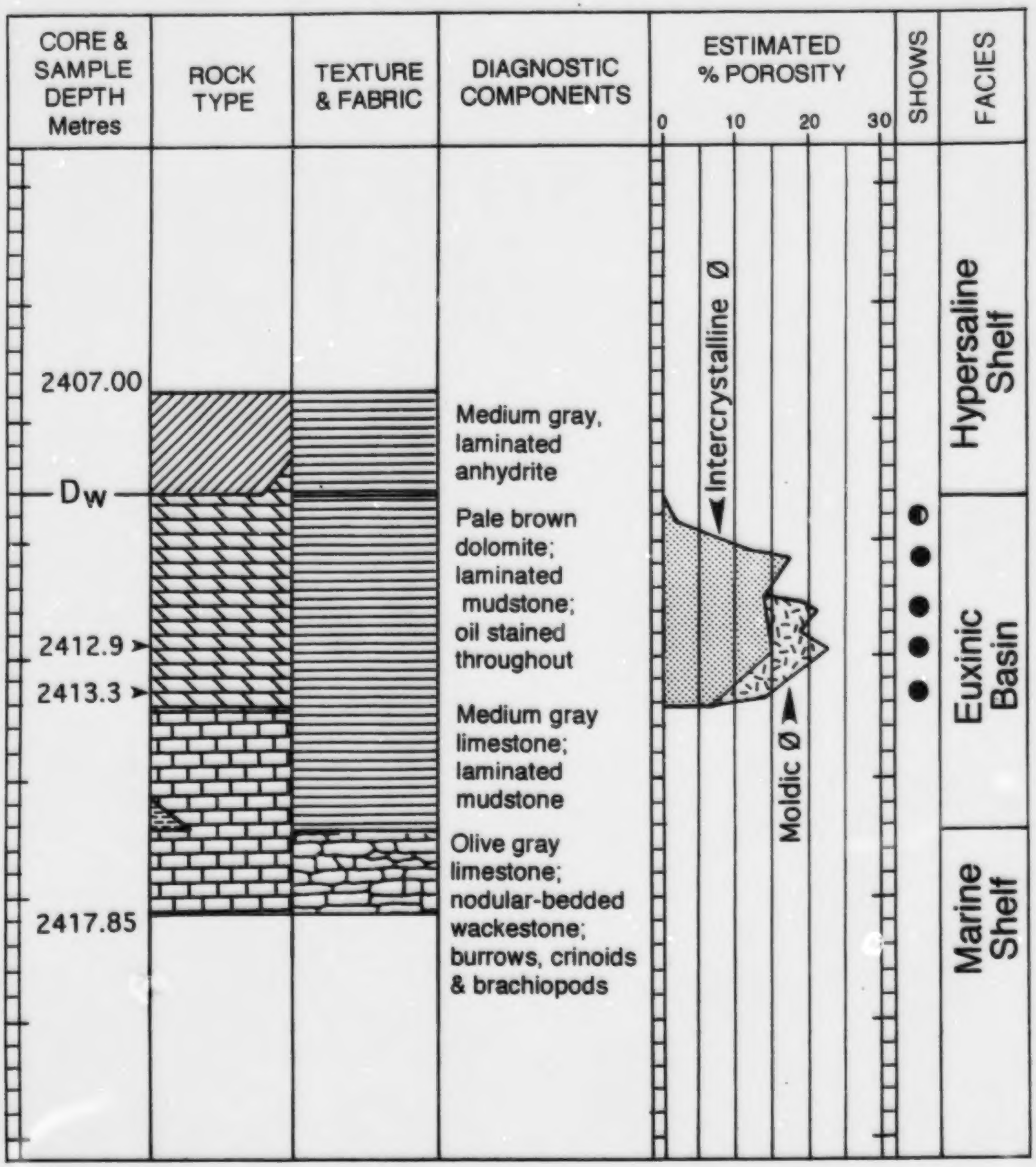


Figure 5 Winnipegosis new pool discovery at Kingsford (Kissling & Slingsby, 1999)



Prairie-Winnipegosis core from Richland Northrock Kingsford 41/8-14-4-7W2 (Kissling & Slingsby, 1999)
Figure 6

Geological Map of Saskatchewan – ver 1.0 (1998) CD-ROM

This CD-ROM includes a bedrock geological map of Saskatchewan and seven geoscience datasets registered to a common projection (NAD27 UTM zone 13) and viewable in a GIS format. This data compilation represents the results of ongoing acquisition, processing, management, and analysis activities at Saskatchewan Energy and Mines. Basemap data provided by SaskGeomatics includes lakes, rivers, railways, NTS grid, cities, towns and parks. Text files on the CD include the Precambrian Bibliography, a listing of all published geological references in Saskatchewan, and metadata files that give a description of each dataset. Most datasets are up to date to September, 1998.

The data are provided in ArcView®/ArcExplorer-compatible SHP/DBF file format. ArcExplorer is a freely distributed viewing and querying software program developed by ESRI® and is included on the CD for hard-drive installation.

Hardware/Software Requirements:

Standard personal computer running Microsoft® Windows 95® or later or Microsoft Windows NT® 4.0 or later, CD-ROM drive, hard drive, VGA or better resolution monitor, mouse or compatible pointing device. Although the software may run on a less powerful computer, due to the size of some datasets, it is recommended that a Pentium 100 or greater with at least 24 MB of RAM be used to prevent slow performance.

Datasets Linked to Map Include:

1. Geochronology - compilation of geochronological ages of Precambrian rocks
2. Lithogeochemistry – compilation of lithogeochemical data analysed in conjunction with SEM and University map projects in the Precambrian Shield area
3. Map Index – information on SEM published Precambrian geology maps
4. Mineral Deposits – information on all known economic mineral occurrences in northern Saskatchewan (partial listing of the fields present in the Saskatchewan Mineral Deposits Index)
5. Mineral Dispositions – location and disposition number of mineral dispositions in northern Saskatchewan
6. Mines – information on currently and recently active mines and test mines in Saskatchewan
7. Oil and Gas Wells – information on all wells drilled in the Phanerozoic sedimentary basin of Saskatchewan (partial listing of fields present in the Well Information System)

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Mechanical Isolation of Highly Conductive Water Bearing Intervals in Horizontal Wells

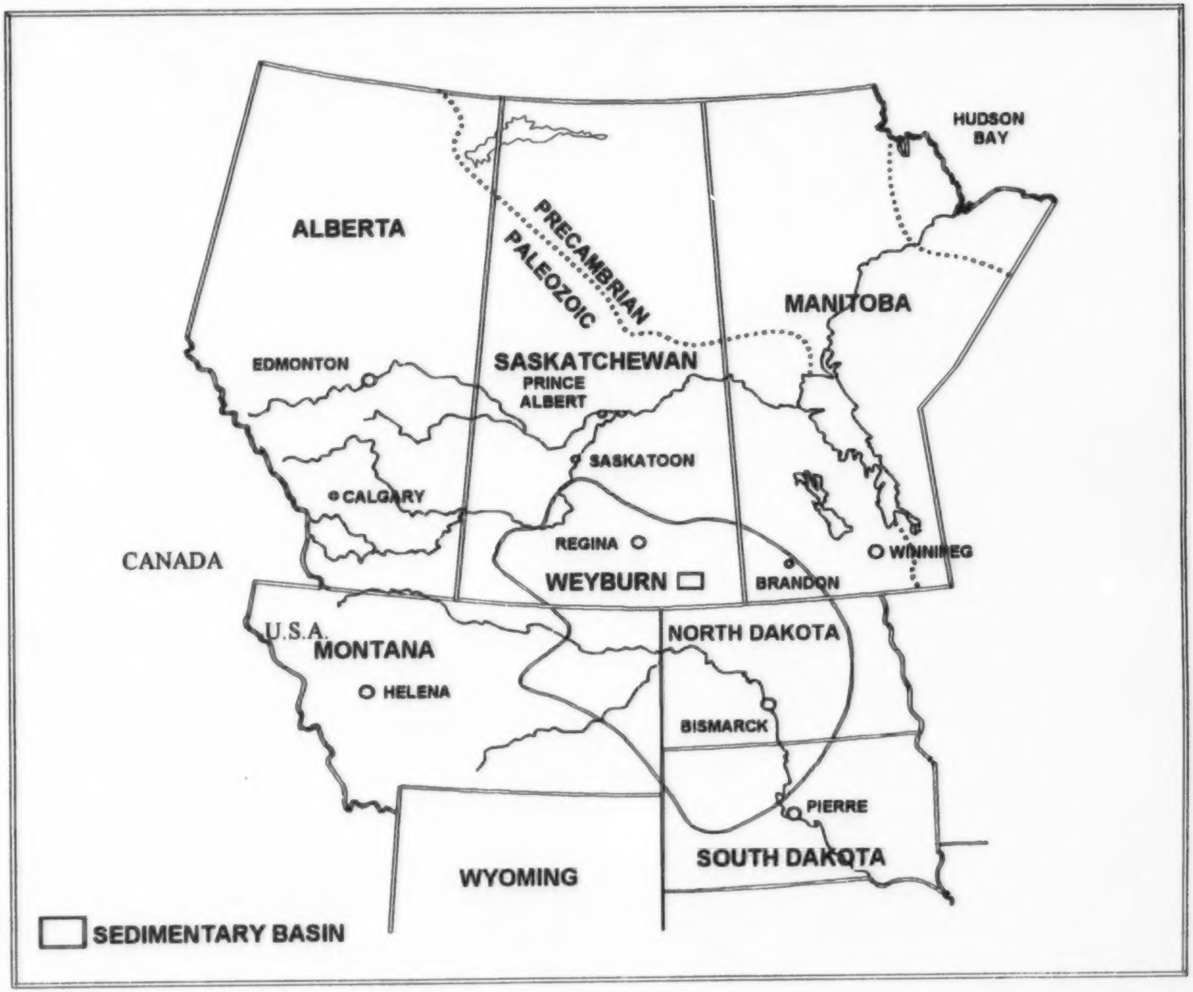
Weyburn Unit, Saskatchewan

Teresa Utsunomiya & Dan Themig

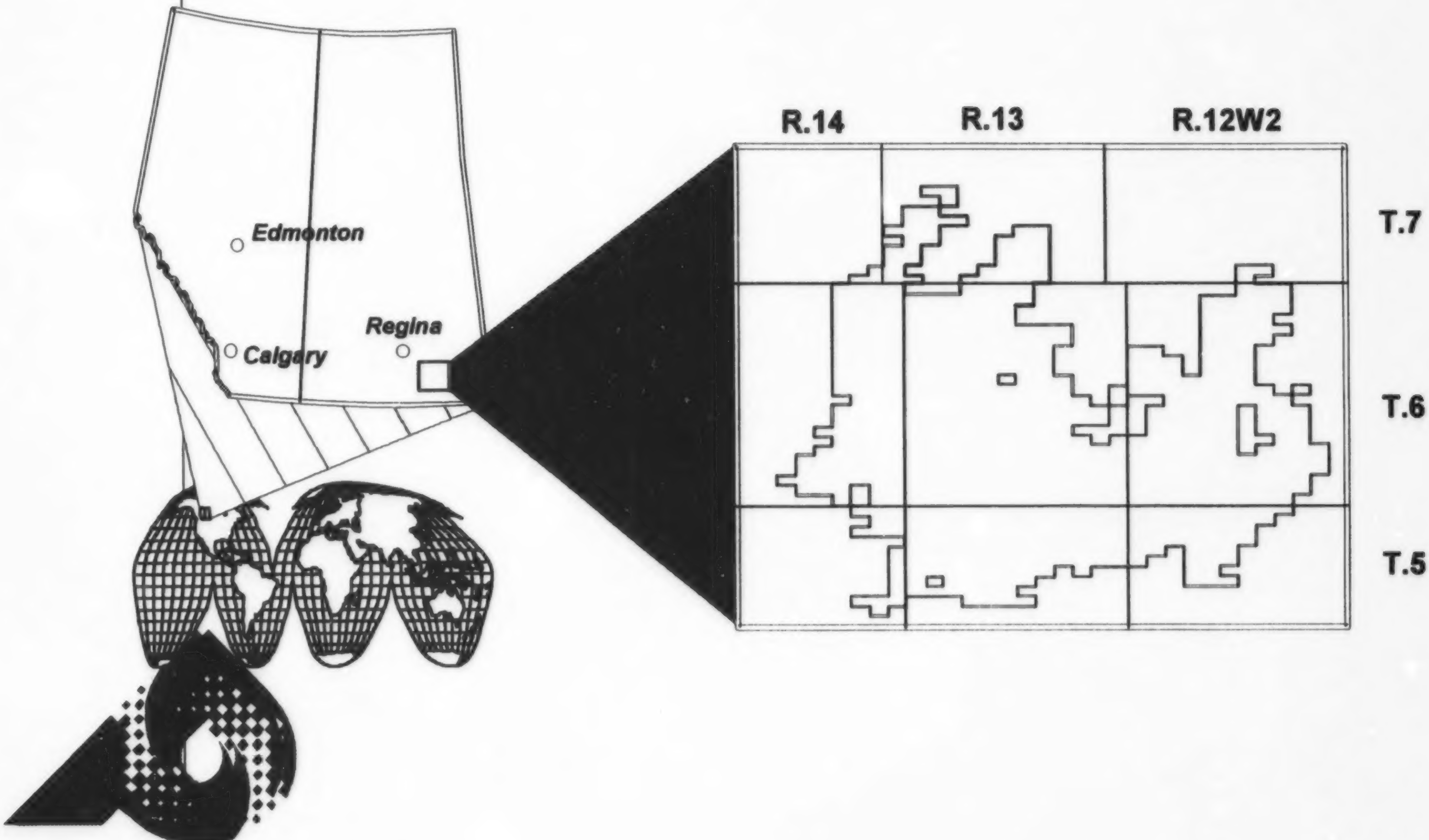
Agenda

- Introduction
- Horizontal Well Intervention
- Geological Setting
- Candidate Selection
- Review of the 1998 Program
- Isolating an interval in a leg
- Isolating a leg in a Quad
- Summary
- Recommendations
- Questions

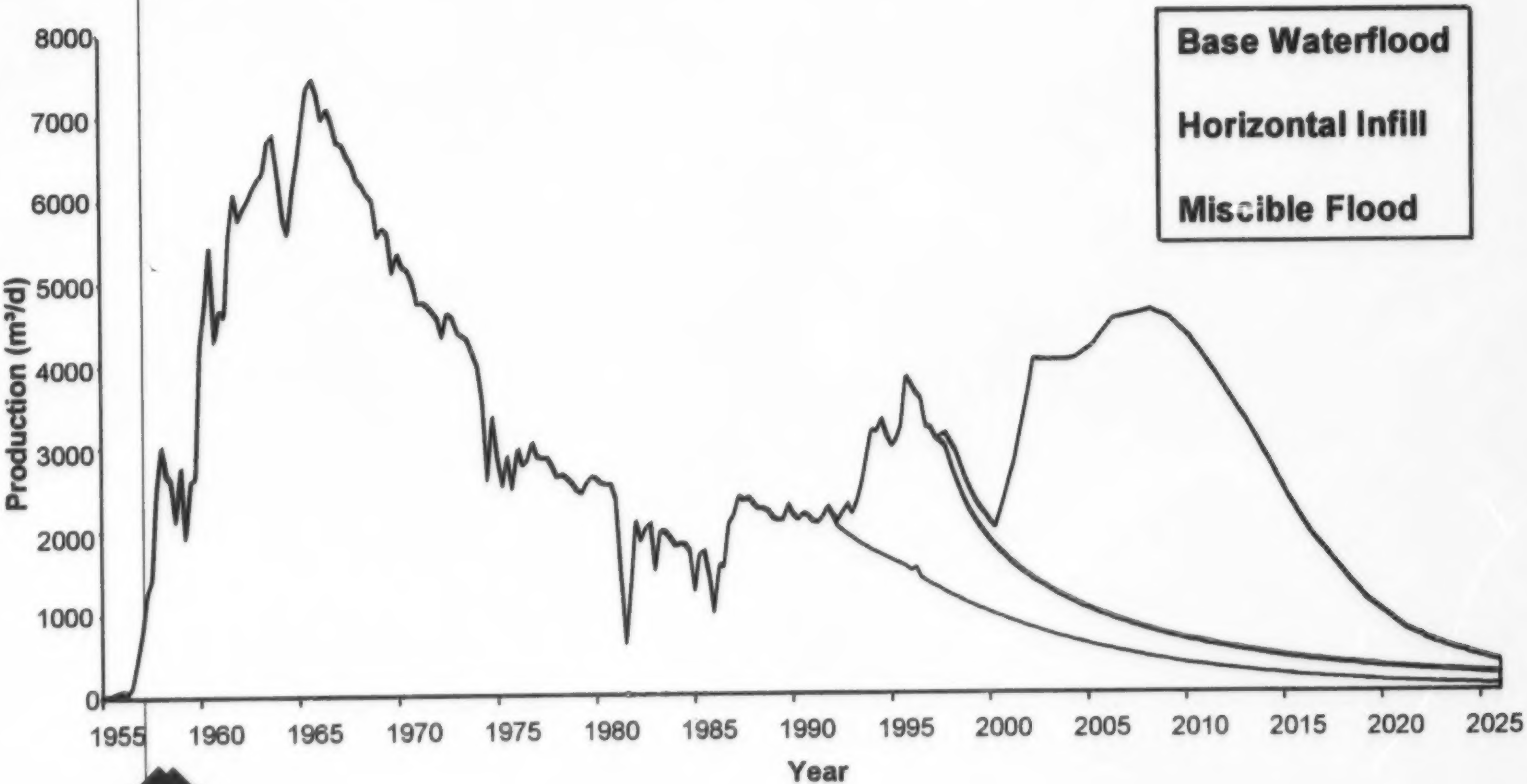
Williston Basin Setting



Weyburn Unit
Saskatchewan, Canada



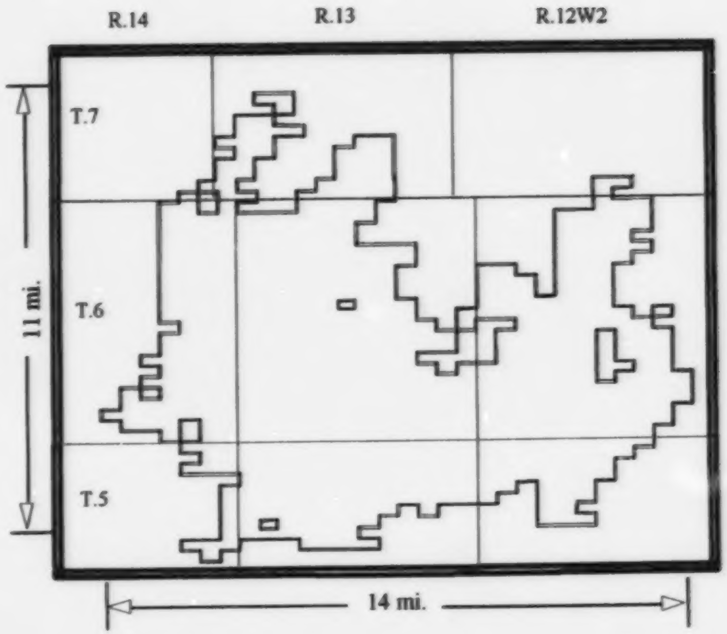
Production History and Forecast



Horizontal Well Intervention

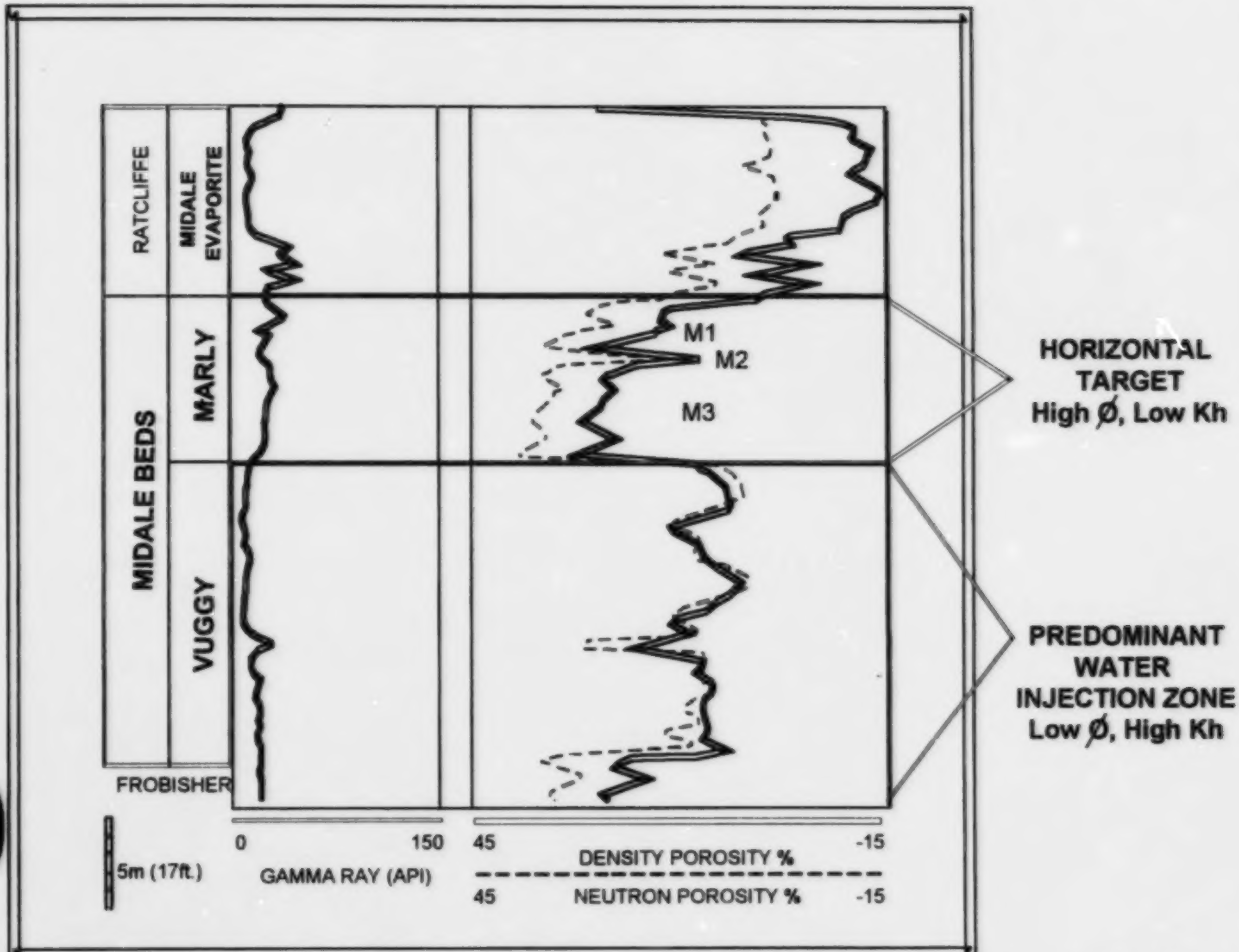
- Strategy
- 141 Horizontal Wells - 285 Legs
- Impact on Pattern Recovery
- Impact on Operating Costs
- Miscible Flood

Weyburn Field - Data Summary

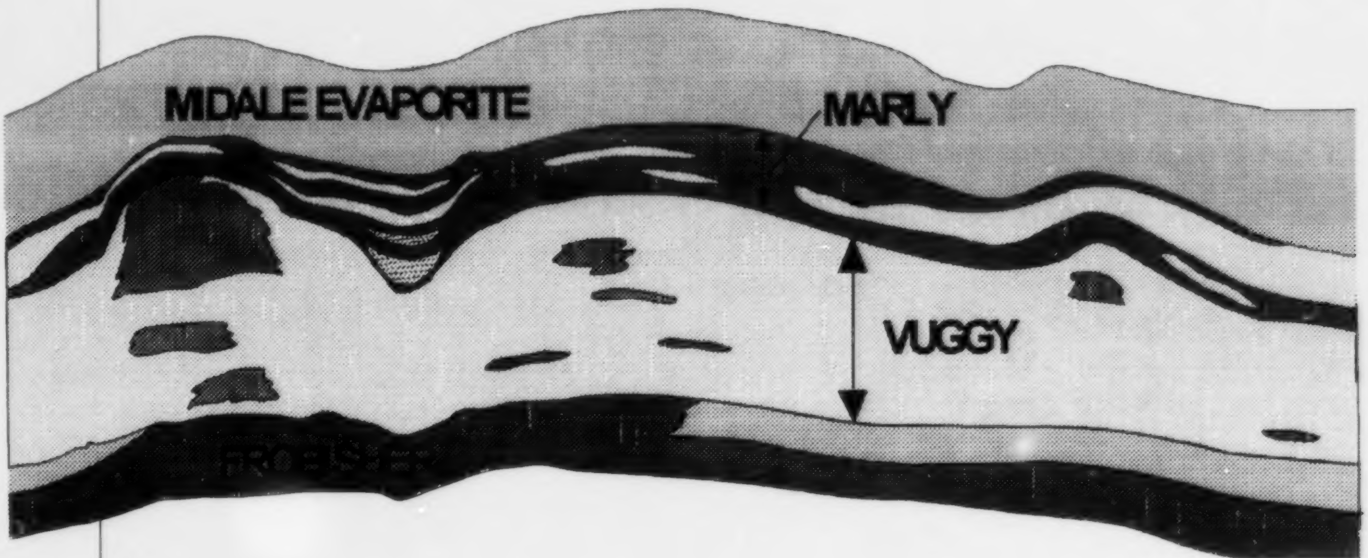


History:	Discovery: December 1954, Production start: 1955, Peak Production: 1965 (7,500 m³/d) (47,000 STB/d) Water Flood: 1964 Horizontal Drilling: 1991	
Trap Type	Hydrological/Stratigraphic	
Formation	Midale	
Age	Mississippian	
Oil Gravity	25 - 34 API	
Orig Res. Press.	14.2 MPa (2059 psi)	
Res. Temp	59 C (138F)	
Bubble Point	4.7 MPa (680psi)	
Gas / Oil ratio	35 m³/m³ (197 SCF/bbl)	
FVF	1.12	
Area	180 km² (70 square miles)	
OOIP	228 10^6 m³ (1.4 billion bbl)	
Current Prod.	3100 m³/d (19,500 bbl/d) - 99/01	
Wells	965 total, 514 vert oil, 138 Hz, 168 inj., 145 susp/abn. (99/01)	
Fluid Drive	Secondary: water flood, Tertiary: intended CO_2	
Reservoir zones	Marly	Vuggy
Depth	1450 meters (4760 ft.)	1460 meters (4790 ft.)
Average ... pach	6m (20 ft.)	15m (50 ft.)
Net Gro... g (Range)	0.5 (0.0 - 1.0)	0.3 (0.0 - 0.7)
P... - Av... ge)	26 (20 - 37)	15 (2 - 15)
...g(Range)	10 (0.1 - 150)	30 (0.01 - 500)

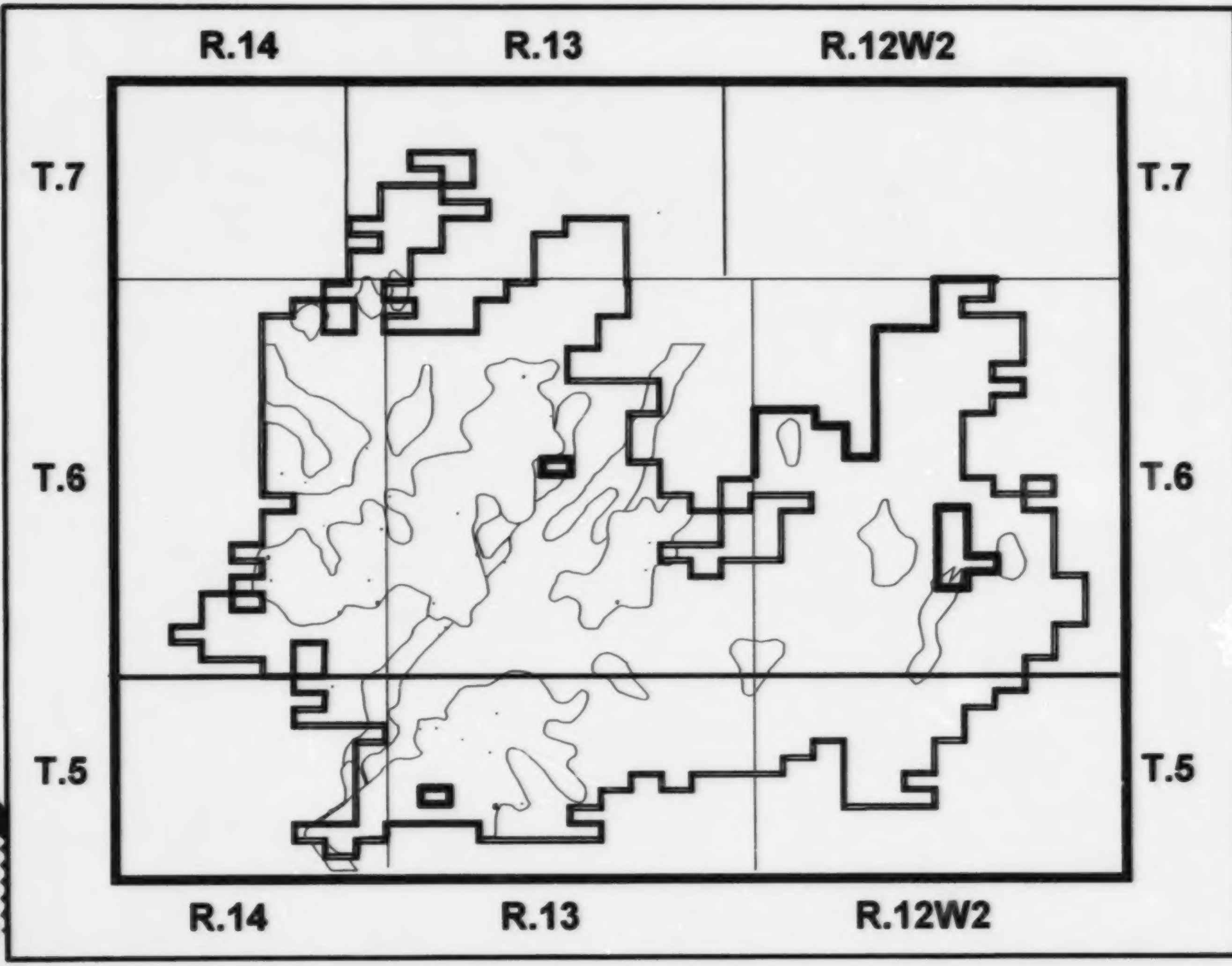
Representative Log Responses
03-32-5-13 W2M



Geological Review
Schematic Cross Section

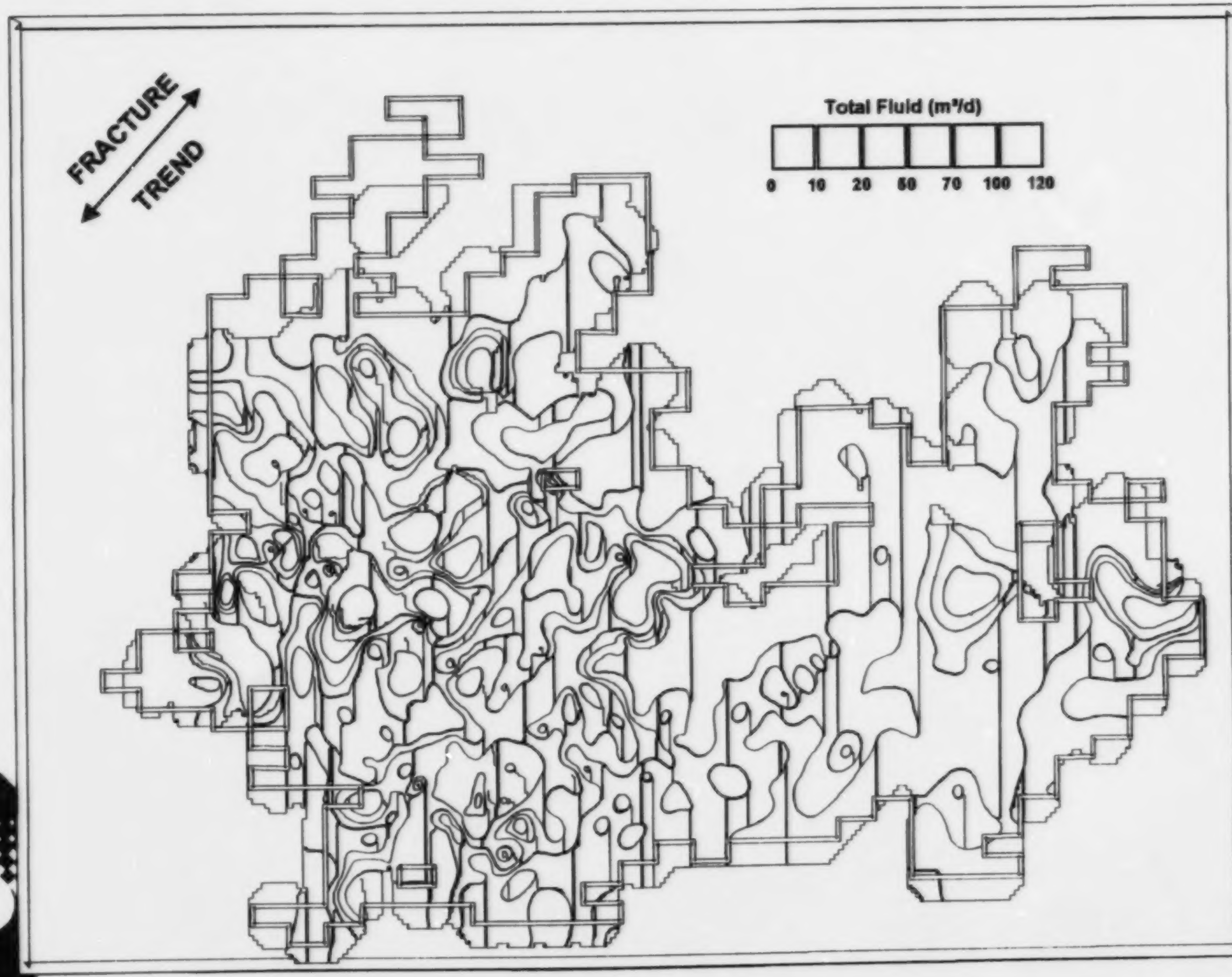


Major Geological Features

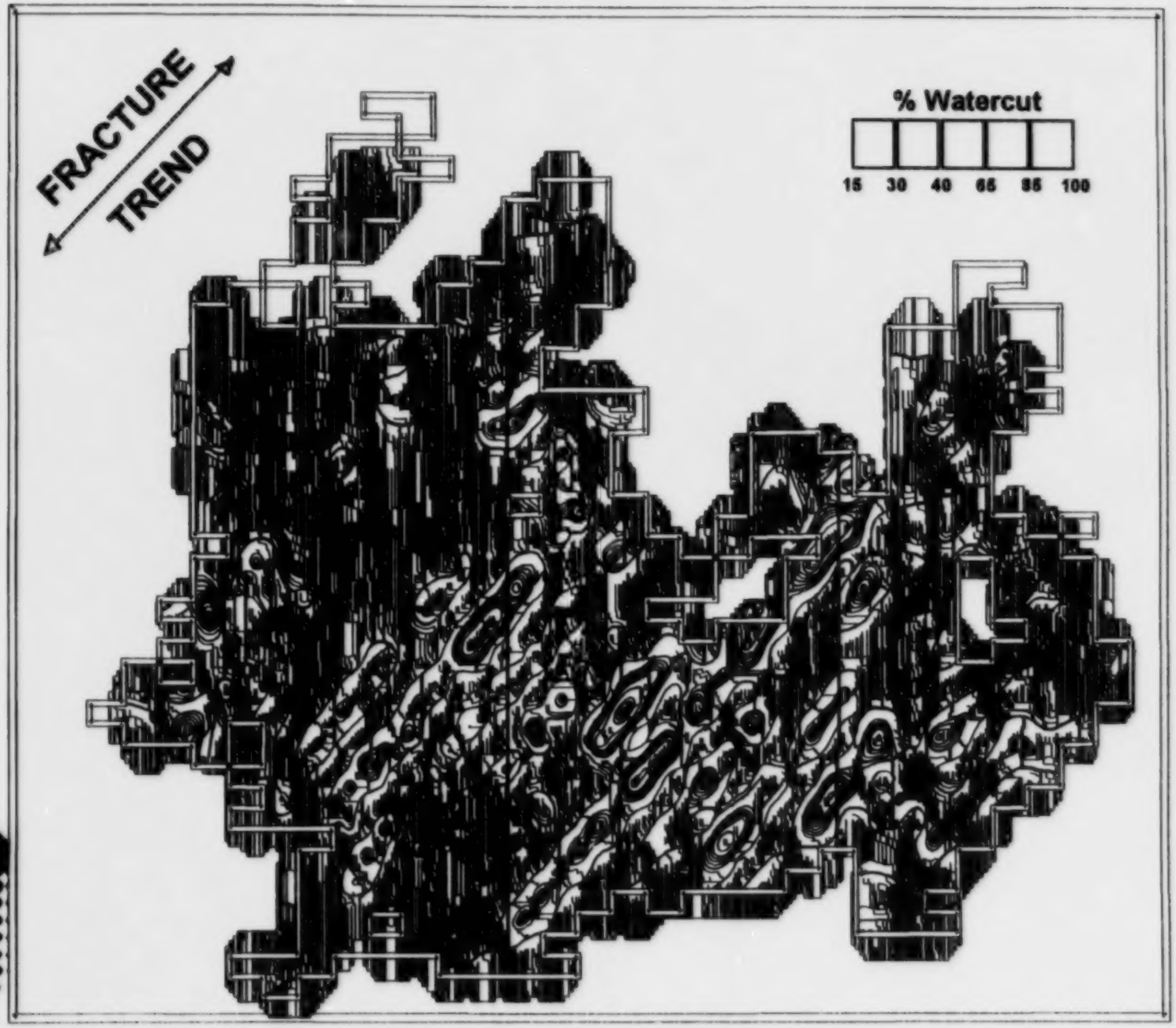


Total Fluid Production

Vertical Wells



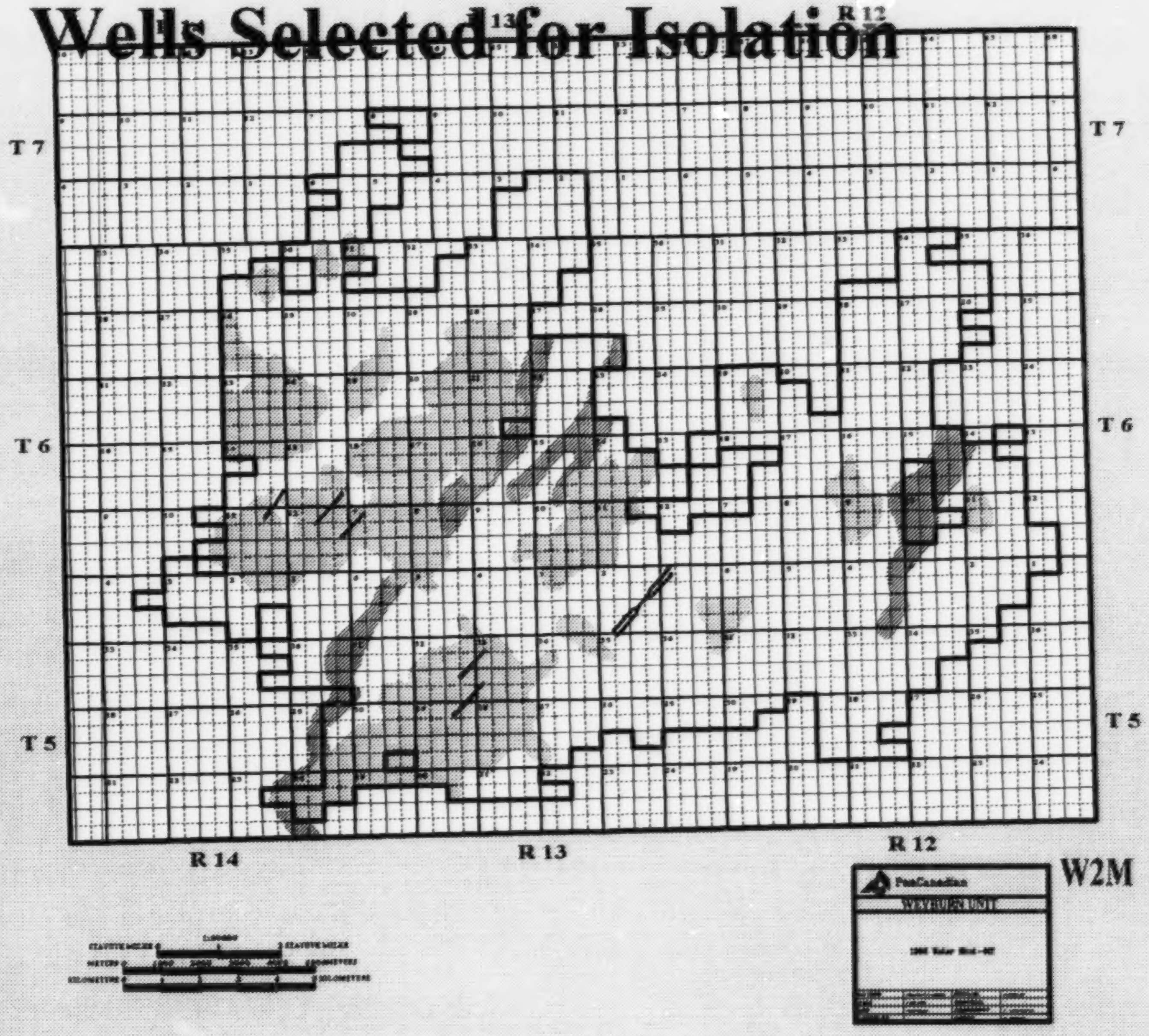
Average Producing Watercut
Vertical Wells



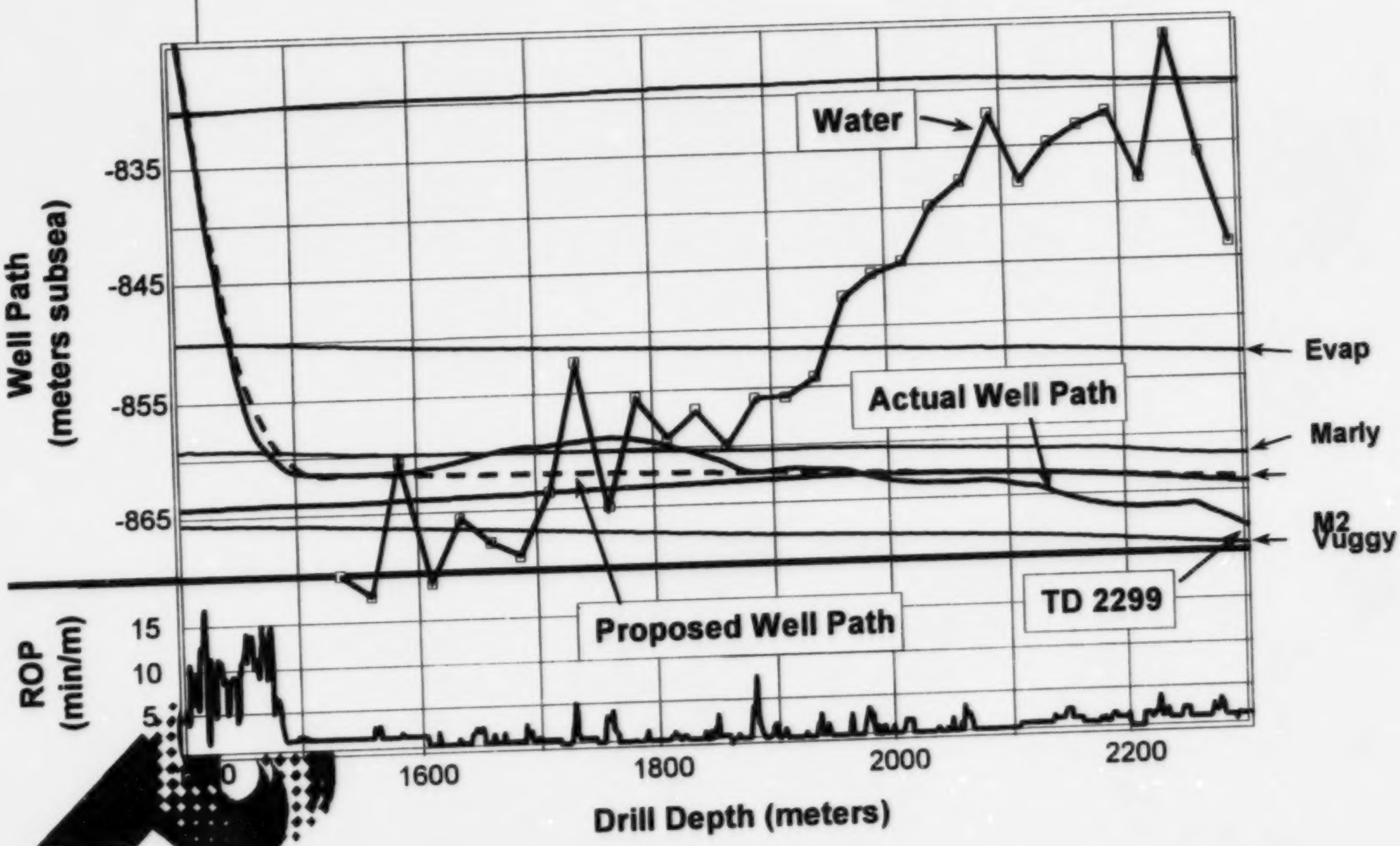
Isolation Candidate Selection Criteria

- High Fluid Levels
- High Watercuts
- Wellbore Path Intersection of M2/M3B/Vuggy
- Fracture Detection Likely (Water Influx)
- Production While Drilling Plots
- Re-entry into Multilateral Wells

Wells Selected for Isolation



PCP et al Weyburn Hz
2A13-33- 4A7-32-5-13



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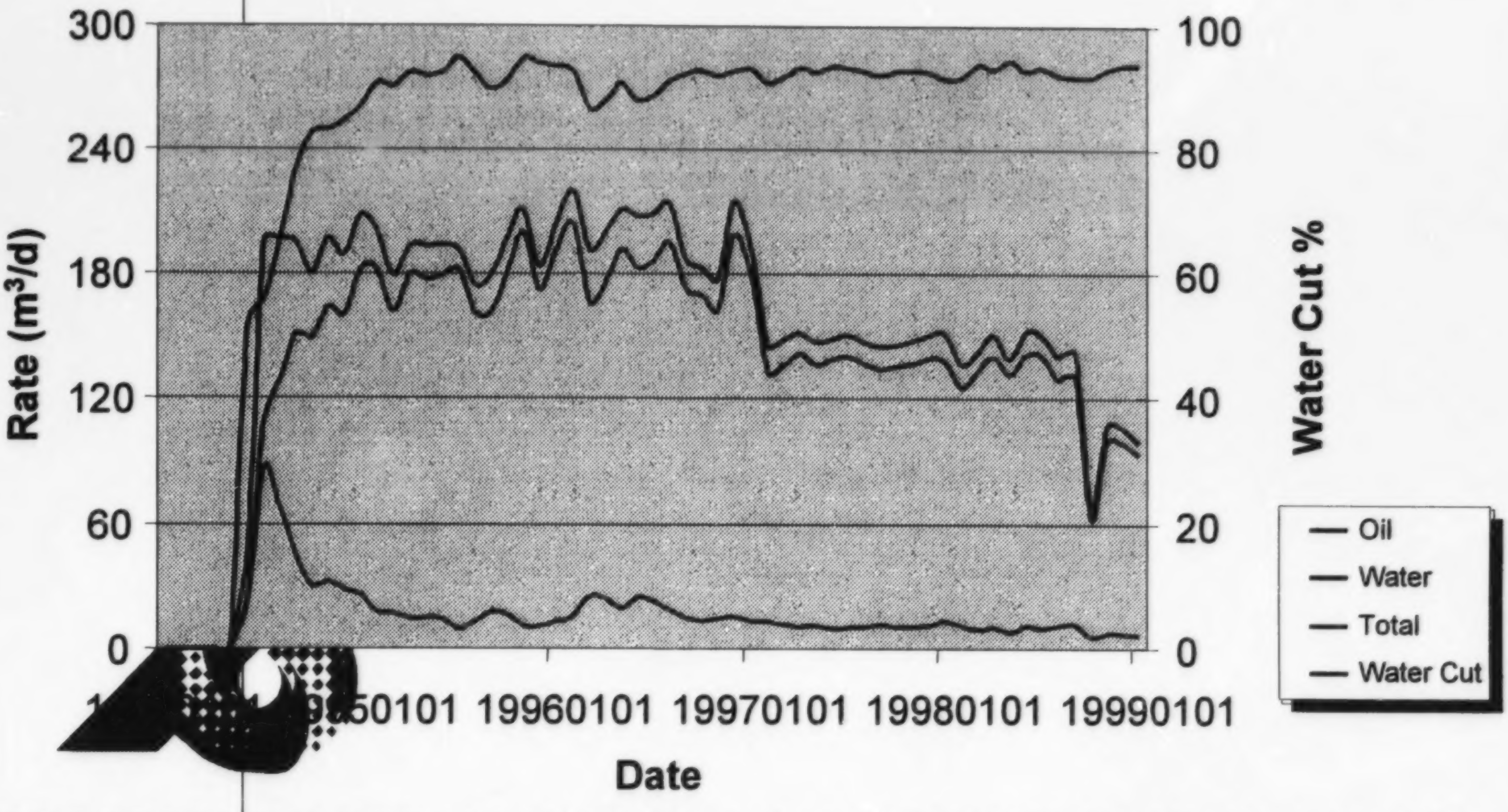
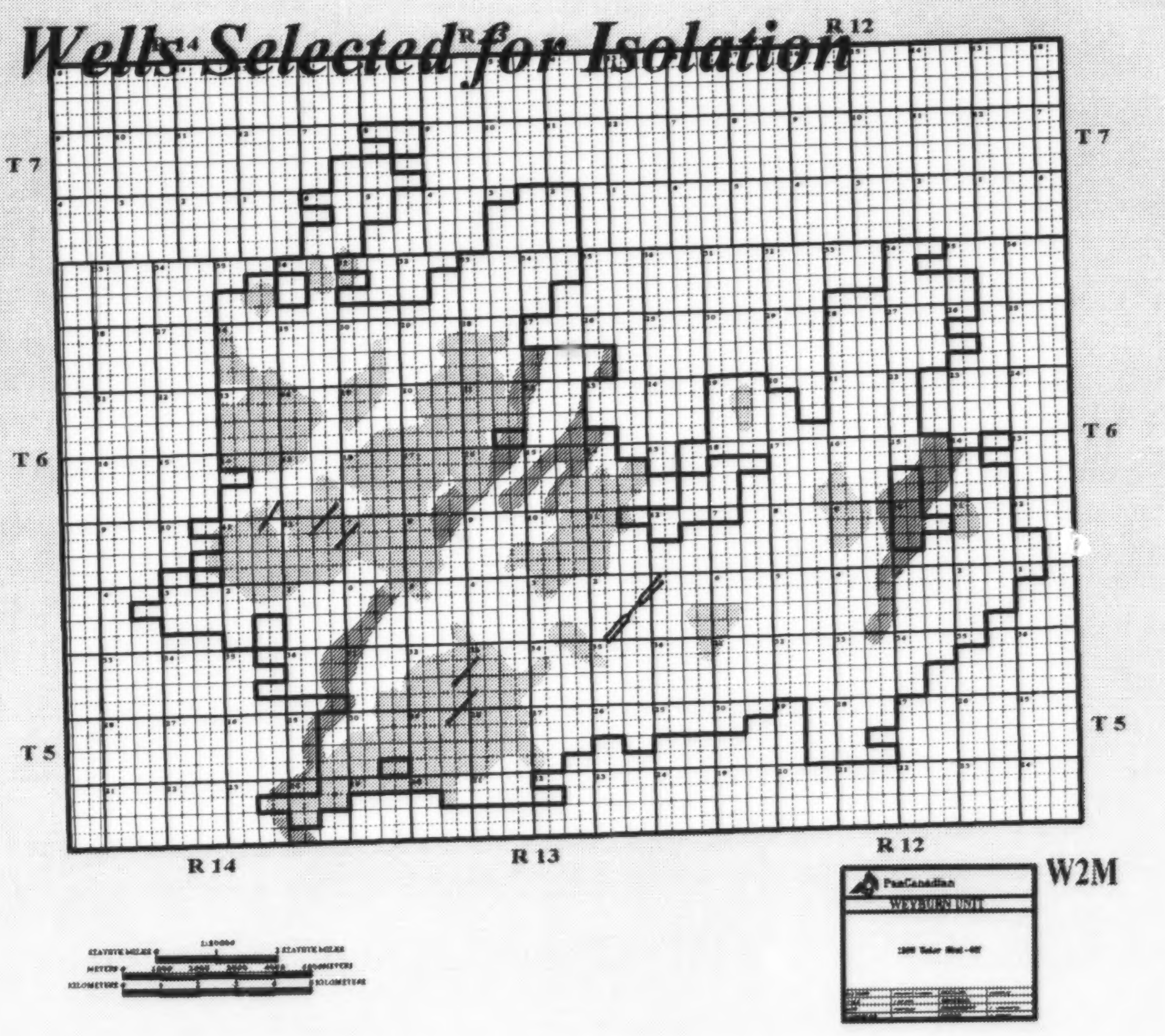
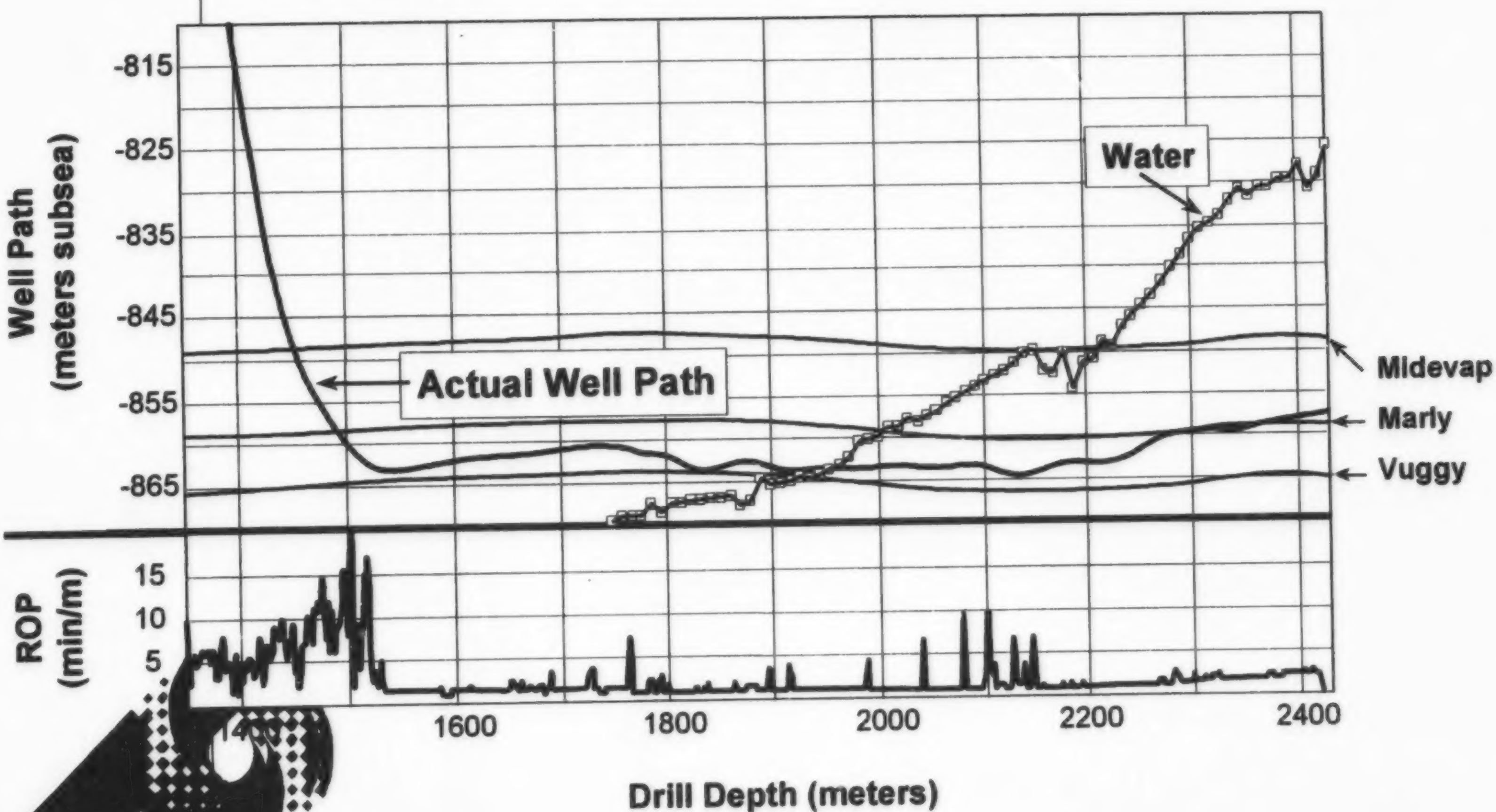
2A13-33-1D7-32-5-13 W2



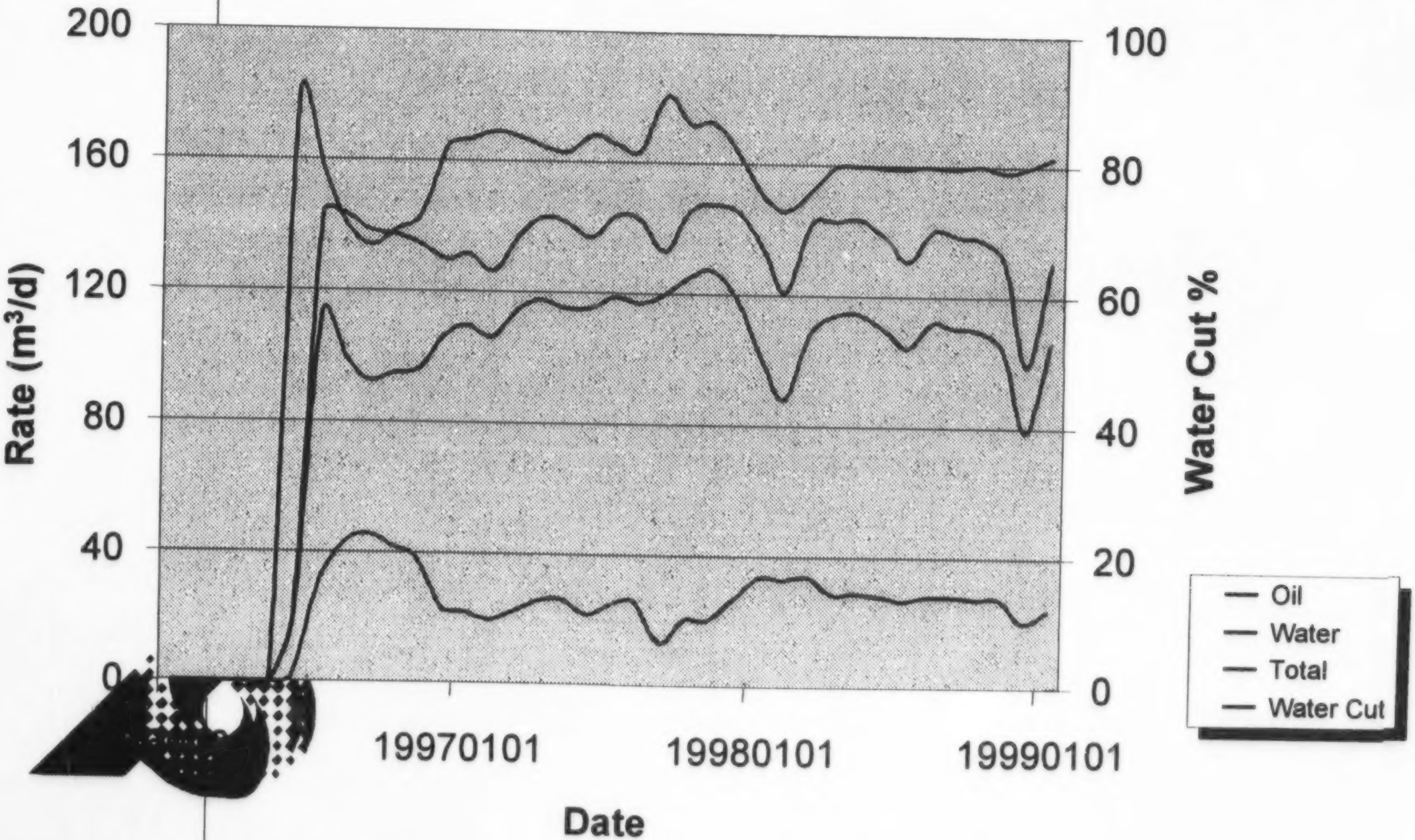
Wells Selected for Isolation



PCP et al Weyburn
4D7-2-1D13-1-6-13



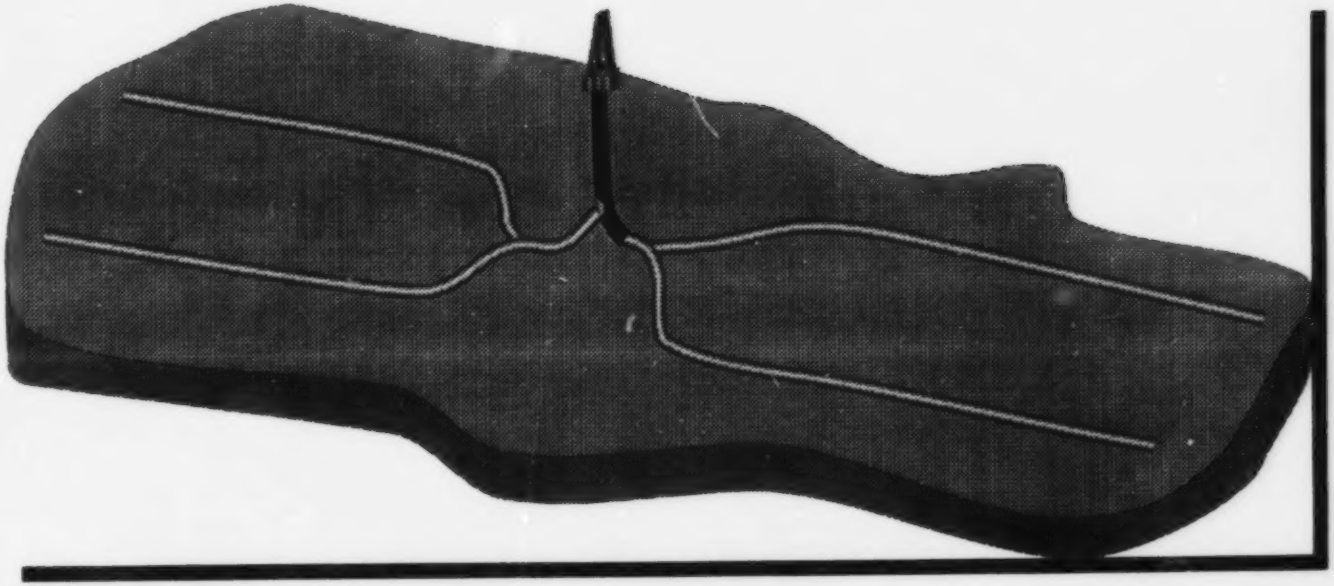
PCP et al Weyburn
4D7-2-1D13-1-6-13 W2



Quad Intervention

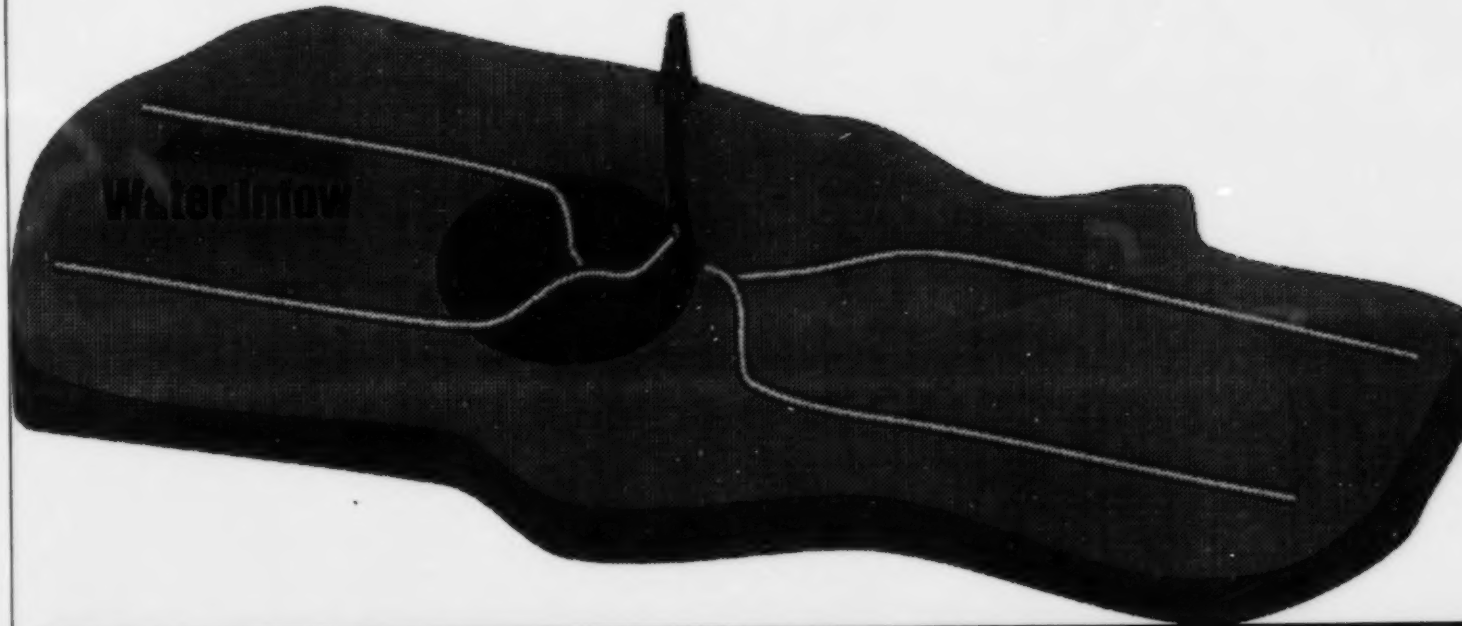
- Access out casing window
- Intervention whipstock required
- Isolation packers
- Anchoring
- Inflow control required

Quad Well Geometry



- Four legs
- Cased juncture
- Open hole juncture

Water Control Problem Defined



- Out casing window
- Open hole juncture
- Inflow control

Isolation Design

- Exit through casing window
- Must pass open hole juncture
- Set and isolate
- Disconnect from assembly

Proposed Quad Isolation Assembly

- Hydraulic set open hole packers
- Running tool
- Piston plug
- Inflow mandrel

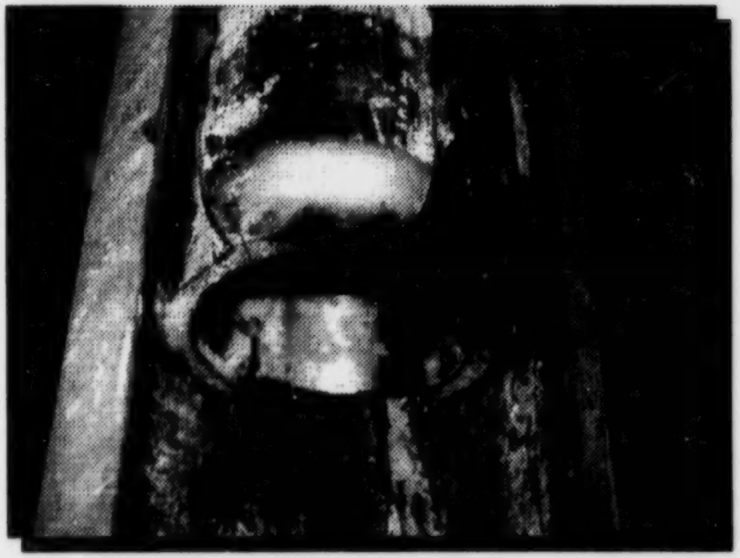
Dresser Oil Tools DRESSER
Guiberson AVA

Mechanical Problems

- Well debris
- Tool design issues
- Compatibility between drilling and completion components
  - Tubing torque limitations
  - Whipstock latch settings
  - Completion rig components

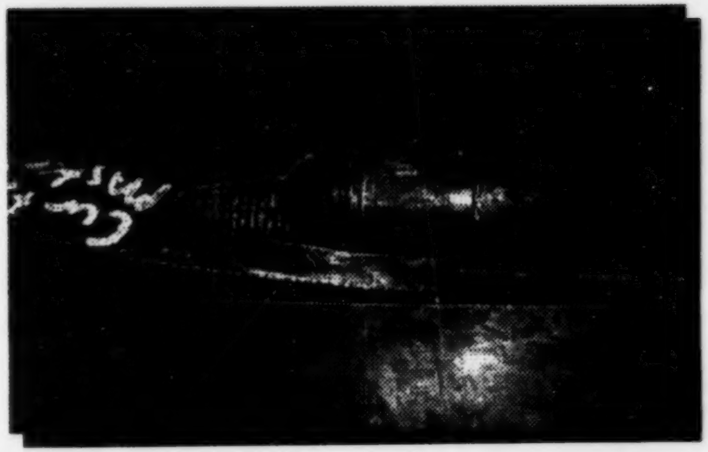
Compatibility Issues - Design

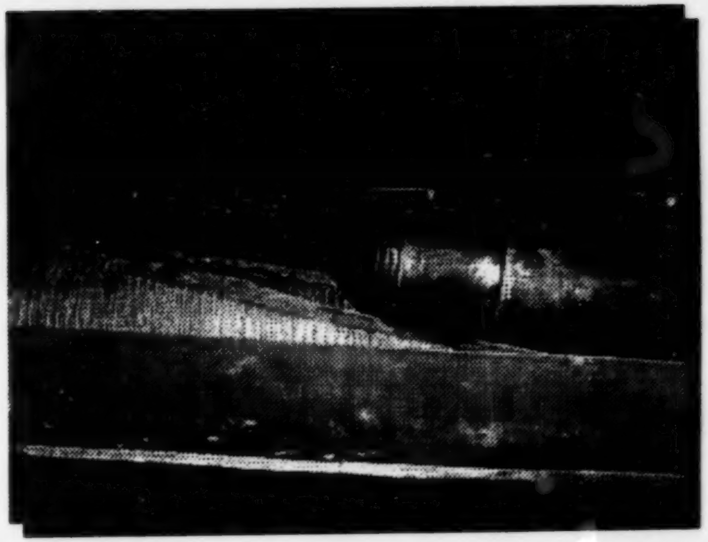
- ML workover whipstock
- Running and retrieving tools
- Completion tool design



Compatibility Issues - Alignment

- Alignment
  - Whipstock latch device
  - Torque requirements
  - Surface indications
- Intervention





Compatibility Issues - Alignment

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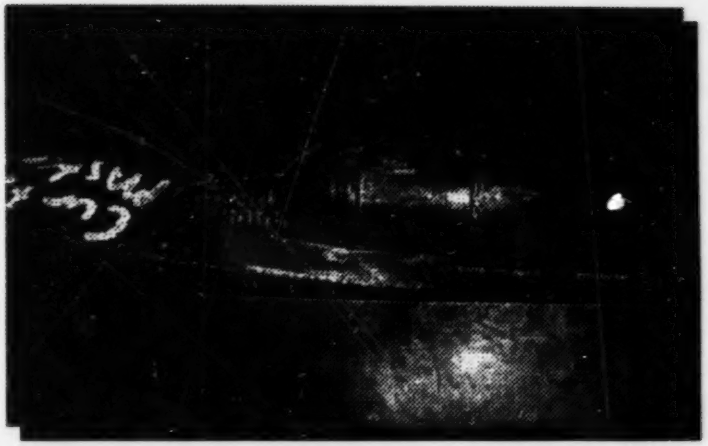
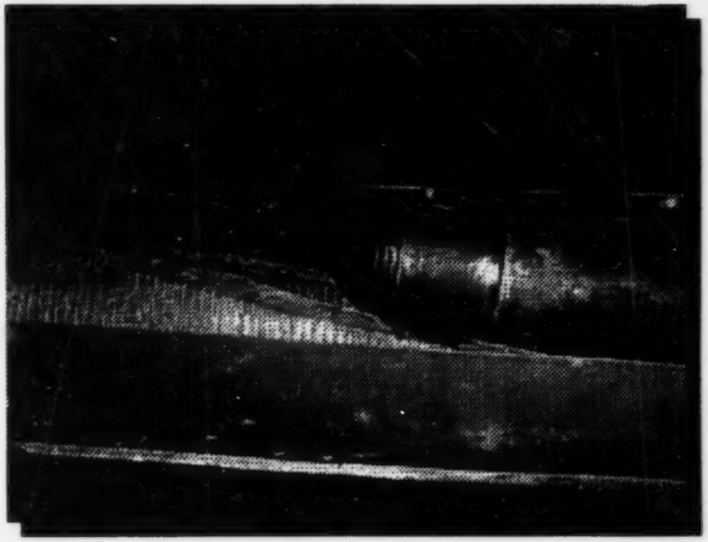
  - Surface indications
- Intervention





Results - Quad

- Unsuccessful access to the lateral
- Well conditions & rig limitations
  - Tubing / torque limits
  - Well debris
- Whipstock mis-aligned
- Corrections and testing in progress

Summary

- Horizontal Well Intervention
- Geological Setting
- Candidate Selection
- 1998 Program Review
- Isolation of an interval in a Single leg
- Isolation of a leg in a Quad

Conclusions

- Importance of Candidate Selection
- Cost Reduction for Future Programs
- Incorporate Drilling Information
- Continue to Evaluate Pressure - Temperature
- Identified Sloughing of Ratcliffe Formation
- Run Caliper Logs - Packer Seat Selection

Conclusions (continued)

- Evaluate Other Logging Techniques
- Swab to Confirm Inflow
- Corrosion Considerations
- Re-entry into Multilaterals
- Review Economics of Well Preparation vs
- Casing Around the Bend

Acknowledgments

The authors would like to thank PanCanadian, the other Working Interest Owners, the Horizontal Well Technical Team and Halliburton Energy Services for the privilege of presenting this material.

SurgiFrac: A Method for Selective Placement of Many Fractures in Uncased Horizontal Wells

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Abstract

To date, the concept of effective uncased horizontal well fracturing is not well defined. Difficulties in regional sealing hamper the fracturing task, and results are generally suspect because of unknown fluid losses throughout the unsealed area. Without proper isolation methods, fracturing uncased horizontal wells is impractical. During many fracturing processes, including fracture acidizing, fracture or acid placement often occurs where fluid first contacts the borehole, often at the heel of the well.

SurgiFrac is a new method that combines hydrajetting and fracturing techniques. By using this new method, operators can position a jetting tool at the exact point the fracture is required without using sealing elements. Unlike other techniques, this new method allows operators to place multiple fractures in the same well; these fractures can be spaced evenly or unevenly as prescribed by the fracture-design program. Large fractures can also be placed with this method.

Because the method is simple, operators can economically bypass damage by placing hundreds of small fractures in a long horizontal section. To further enhance the process, operators can use acid and/or proppants to place a combination of the two fracture types in the well.

This paper discusses the basic principles of the SurgiFrac process and how its unique dynamic diversion process can be effectively applied in the field.

Introduction

Hydrojetting, the use of water under high pressure, is a well-known technique that many industries use to perform different tasks.[1] These tasks include cleaning and preparing surfaces, placing cements, drilling, cutting, slotting, perforating, machining, grouting, and mining, and household uses such as car washing and dental hygiene. Sand-laden fluids can be used, or cavitating jets may be required. Jet pressures range from a few hundred psi to 60,000 psi. The hydrojet (or hydrajet, when sand or another abrasive is used) process concentrates high-power energy on its target.

In the oil industry, the most common applications for hydrajetting are slotting (cutting) or perforating. In these applications, sand performs the abrasive cutting function. Over time, jet system quality has improved dramatically, resulting in greater resistance to abrasives and various chemicals, and significantly increased tool life. With the advent of better and more reliable tools, this technology is suitable for oilwell stimulation.

Horizontal Well Completions

The first horizontal well was completed successfully in 1939,[2] but horizontal wells were not routinely used until the 1980's. This first horizontal well was drilled to a depth of 630 ft, and it was extended laterally for 802 ft (**Fig. 1**). A branch created somewhere in the horizontal section dipped down to another payzone at a depth of 953 ft, making it the first

horizontal and multilateral well. The lateral well was cased near the main wellbore, while the remainder was completed openhole. The openhole sections were fracture-stimulated with 1,150 lb (521.6 kg) of TNT. Fifty-nine years later, with improved technologies, horizontal well completions are a routine economic-exploitation technique in certain formations. The ability to steer while drilling allows operators to drill these wells from the surface, instead of sending mining crews downhole.

Noncemented horizontal well completions include true openhole completions, slotted- or perforated-liner completions, or liner completions with external casing packers. Cased and cemented completions can also be used on horizontal wells. Reservoir rock properties and the owner/operator's initial investment influence the appropriate completion selection. Generally, most horizontal wells in competent formations receive openhole completions.

Often, wells drilled and completed in low-permeability formations sustain formation damage, thereby limiting productivity. For increased productivity and improved economics, these wells must be stimulated with acidizing or hydraulic fracturing treatments.

Hydraulic Fracturing

In hydraulic fracturing, pressurized fluid fractures the formation. Fluid pressure in the wellbore is increased until it exceeds the formation's breakdown pressure, creating one or more fractures at the wellbore. This pressure is commonly known as the fracture initiation pressure (FIP). After the well is fractured, the pressure necessary for the fracture to grow, the fracture extension pressure (FEP), is generally less than the FIP.

In the 1970's, horizontal wells were reintroduced to avoid fracturing. In formations with sufficient vertical permeability, fracturing is unnecessary. Because they are economical, uncased horizontal completions have become commonplace. However, if these wells need to be stimulated, excessive flow rates are often required to fracture these wells because the extremely large wall surface of the wellbore allows fluid to leak off into the formation. Therefore, the optimum solution requires an effective tool or method that can divert this flow into a limited zone.

The industry's first solution included static diversion techniques that typically used mechanical systems to divert fluid flow into a short section of the formation. One such device, known as the straddle-packer system, uses two hydraulically activated packers that are located a few feet apart. Fracturing fluids are injected into the well section between the two packers. The system was ineffective because near-wellbore stress distribution caused small fractures to jump past the packers and communicate to other sectors of the wellbore (**Fig. 2**). Generally, static diversion techniques are ineffective, impractical, and uneconomical.

The SurgiFrac Concept

SurgiFrac is the first recorded attempt to resolve the openhole-fracturing problem with dynamic diversion techniques. Instead of using mechanical or chemical seals, the system uses the fluid's own dynamic movement to divert fluid flow into a specific point in the formation.[3,4] This concept is primarily based on the historic Bernoulli [3,5] concept, expressed by Eq. 1:

$$\frac{V^2}{2}+\frac{p}{\rho}=C \qquad (1)$$

where V is fluid velocity, p is fluid local pressure, ρ is fluid density, and C is a constant.

The SurgiFrac concept uses a specially designed high-pressure hydrajet tool (a SurgiFrac tool) that is commonly used in oilfield applications to abrade or penetrate steel casing or rock formations. The SurgiFrac tool initially forms a few perforating tunnels of limited depths (**Fig. 3**). The velocity of the fluid flowing into the perforation tunnel is very high, and the tunnel length is usually short (about 12 in.). The velocity becomes very low near the bottom of the perforation, as shown on the right side of Fig 3. Based on Eq. 1, and the addition of a fracture dimension, the stagnation pressure can be plotted and shown as the dotted line in **Fig. 4**. Note that this pressure line only indicates pressures at each location if no flow (i.e., no fracture extension) exists.

However, the boost-pressure plot in Fig. 4 is more important because it describes the dynamic pressure distribution based on momentum preservation:

$$\sum F=\frac{d(mV)}{dt} \qquad (2)$$

where F is force, m is mass, d is diameter, and t is time.

Deriving the above relations to relate to a "jet pump" or an "artificial lift" system,[6] we get

$$Boost=\frac{W_j^2}{\rho g^2 A_j A_f}-\frac{W_f^2}{M^2 \rho g^2 A_f^2} \qquad (3)$$

where *boost* is the dynamic pressure boost by the "virtual artificial lift" pumping system, W is the weight flow rate, A is the area of flow, g is gravity, and subscripts j and f denote the jets and the fracture, respectively. M is the weight-flow contribution ratio by the annulus defined as

$$M=\frac{W_a}{W_j+W_a} \qquad (4)$$

where the subscript a denotes the annulus.

In Fig. 4, the boost pressure is lower than the stagnation pressure. As W_j increases, this value also increases. Therefore, when using SurgiFrac, we *must* maximize jet flow rate for every situation. Also in Fig. 4, we are only interested in the value of the peak pressures because the right side of the curve would adjust itself to the formation's governing parameters.

The values used in Fig. 4 are based on the use of 12.1875-in. jets, with jet pressures of 5,000 psi. The figure shows that the boost pressure is about 350 psi, while the stagnation pressure is about 430 psi. If this value is the actual pressure level downhole, then no fracture will occur. Therefore, the annulus pressure must be maintained at a level slightly below the fracture-initiation pressure. This balancing act requires flowing into the

annulus at rates that will boost the pressure as needed. This flow rate requirement is generally much less than the required rate to pressurize the well for unbounded fracturing. In general, SurgiFrac will reduce flow rate requirements by 35% (in 15,000-ft TVD wells) to 80% (in 4,000-ft TVD wells). Fig. 4 also shows the stagnation pressures that occur before the fracture begins (i.e., the stagnation within the perforation tunnels). Note that stagnation pressure is greater before fracture initiation. During the perforating stage, stagnation pressure is about 360 psi, but it drops to 205 psi when the fracture begins.

Hydraulic Fracturing With SurgiFrac

SurgiFrac requires a new approach to job treatment design because the conventional computing methods for a fracture design are no longer valid. For example, two primary fluid flows need to be controlled and evaluated, which immediately requires two separate pumping systems. Other important issues are the ability to pressurize the annulus at flow rates that are not prohibitive and the types of fractures (small or large, sand or acid, etc) that are to be made in the well. Moreover, the stimulation designer must now decide where the fracture will be made, because SurgiFrac can place many fractures with *surgi*cal accuracy, as shown in **Fig. 5**.

To deliver jet pressure downhole, operators use a pipe inside the casing. This pipe could be a jointed tubing string (for any size fractures) or coiled tubing (for small fractures to bypass damage). High-pressure treatment fluid is sent downhole through this tubing string. On the outside of this tubing, another flow is pumped into the well. So, unlike hydrajetting jobs where fluid circulates up the annulus, SurgiFrac jobs direct all flows downward. This important difference must be noted, both in the design and analysis of the job and in the practical aspect of the job. In hydrajetting, sand-laden fluids are circulated up the annulus, often causing the tool to get stuck in the well. With this new technology, sand-laden fluids never move upward, minimizing the probability of a stuck tool.

From downhole pressure tests, one could find out whether large or small fractures are required for the well. For example, if a large skin is detected, many small fractures (perhaps every 10 ft) can be placed effectively with coiled tubing systems. However, if a far-wellbore restriction is discovered (although skin is high), then we would probably opt for large fractures to connect to the distant producing formations.

SurgiFrac Treatment Case Histories

Like any other "new concept" treatment, SurgiFrac was exposed to many different circumstances. Each stimulation job provided more insight about the system's capabilities or insufficiencies. For this paper, each job performance is evaluated in relation to the success of the SurgiFrac process, which may or may not reflect the true end result: the productivity of the well. This focused approach is necessary because either we cannot release the data or the well may not have been a good candidate for the process. Often, new processes are attempted on "impossible" wells. The following six treatments were made with this process, and the results are shown in **Table 1**.

Well A

Well A was completed with a 7-in. casing to 11,503 ft., with a 4,500 ft, 6 1/8-in. openhole horizontal section. Seventeen fractures were planned with the SurgiFrac process; each fracture was strategically placed throughout the horizontal section. The job used a 3 1/2-in. tubing string equipped with a 14-jet SurgiFrac tool, a centralizing ball sub, and a pressure recorder. Each fracture was designed to receive an average of 10,000 lb of 20/40-mesh intermediate-strength proppant. The fracture gradient was calculated at approximately 0.62, so the required annular pressure was about 2,200 to 2,300 psi.

However, because of well competency issues, we were only allowed to pump at 1,000 psi (1,200 psi below FIP) for 14 of the fractures. We were allowed to increase to 1,500 psi for two of the fractures and to 1,800 psi for one of the fractures. With the jet configurations, boost pressures were determined to be about 430 to 600 psi. By consensus, we estimated that only three fractures were made successfully during this treatment.

Well B

Well B was completed with a 5 1/2-in. casing to 3,821 ft, with a 4 3/4-in. lateral openhole. Eight fractures were planned; again, each was placed strategically throughout the lateral. The job used a 2 7/8-in. tubing string with a 12-jet SurgiFrac tool, including a centralizing ball sub and a pressure recorder/transmitter. This acidizing/fracturing job used 17% HCl. FEP was estimated to be 2,200 psi, and it was reached with a 600-psi pumping pressure through the annulus. The boost pressure that was possible with this configuration was computed to be 370 to 465 psi.

The job was completed within 5 hours, and all eight fractures were successfully created, resulting in a production increase of about 800%.[4] **Fig. 6** shows the tool being inserted in the well. The treatment was also tagged, and the subsequent tracer logs (**Fig.7**) show fractures at precisely planned fracture points.

Well C

Well C was completed with a 7-in. casing string and cemented to 9,800 ft MD. The bottom 1,000-ft section slanted about 30° from vertical, indicating that the formation was also slanted. The 1,000-ft section was perforated conventionally, and a fracturing treatment was attempted unsuccessfully. At extremely high pressures, fluid flow could not exceed 1 bbl/min. Heavily overbalanced jet perforation was subsequently attempted with the same results.

Finally, we recommended the SurgiFrac approach. We used SurgiFrac to perforate the casing and create a small, disk-shaped cavity and fracture. Then we fractured the well conventionally. This job was not exclusively a SurgiFrac treatment because conventional fracturing was still planned for the job. However, the job was a great success because fracturing was performed easily with low fracturing pressures.

Well D

Well D was completed vertically with a 7-in casing string to 1,700 ft, and then the casing was bent into the horizontal until it reached 2,200 ft MD. An 800-ft lateral was completed with a 4 1/2-in. slotted liner. Three fractures were planned with 110,000 lb of 10/40-mesh sand per fracture. The job used a 3 1/2-in. tubing string to about 1,500 ft, then changed to

$2^3/_8$-in. tubing below. A nonstandard, third-party, four-jet tool was used for this process. FEP was estimated at 1,020 psi, and it was reached with a 400-psi pumping pressure through the annulus. Jet pressure was 4,000 psi, and the boost pressure was computed to be approximately 173 to 193 psi.

During the first fracture, the job went smoothly until 105,000 lb of sand was placed into the fracture. Soon afterward, the tool failed, and the job was terminated. During the second and third fracturing operation, the tool failed very early in the process.

Well E

Well E was completed with 7-in. casing to 10,860 ft, then a $6^1/_4$-in. horizontal, openhole section was drilled to 4,600 ft. A $3^1/_2$-in. production tubing (2.92-in. ID) runs the entire length of the 7-in. casing string. The intent of the job was to place 33 small fractures along the openhole with $1^3/_4$-in. coiled tubing. Each minifracture was to be made with 300 gal of 28% HCl. FEP was estimated at 8,688 psi, and it was achieved with approximately a 3,600-psi pumping pressure into the annulus. With this three-jet, coiled tubing system, the computed boost pressure was only between 35 and 36 psi, which hindered the creation of substantial fracture sizes. Fortunately, large fractures were not the intent, and all 33 minifractures were placed successfully. The job was completed within $8^1/_2$ hours.

Well F

Well F is a 10,850-ft well with a 1,000 ft horizontal openhole. Similar to Well E, the vertical section has a $3^1/_2$-in. production string with a 2.92-in. ID. The job used 2-in. coiled tubing fitted with a three-jet SurgiFrac tool. Annulus pressure was limited to 2,000 psi, thereby limiting fracture size. Tiny fractures at the bottom of the perforation tunnels were deemed satisfactory, and a localized injection pressure of at least 200 to 300 psi into the matrix was acceptable. More than 120 acid "fractures" were made with this procedure; each used 250 gal of 15% HCl.

Conclusions

A new, effective method for fracturing uncased horizontal wells has been presented. Experience shows that the method requires different prejob calculations, mainly for the annular flows (the fluid dynamics coming out of the jets), which translates to a valuable boost-pressure determination for the job. Fluid-flow calculations are unique for this application, because it combines jet technologies and fracturing technologies into one new stimulation technology. Experience also shows that SurgiFrac is not suitable for all conditions. To make this new technology successful, operators must carefully consider each candidate well's suitability.

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3. Surjaatmadja, J.B., Grundmann, S.R., McDaniel, B., Deeg, W.F.J., Brumley, J.L., and Swor, L.C.: "Hydrajet Fracturing: An Effective Method for Placing Many Fractures in

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6. Fitch, E.C., and Hong, I.T.: *Hydraulic Component Design and Selection,* Book 1 of the Computerized Fluid Power Design Series, BarDyne, Inc. (1997) 410-415.

Table 1—SurgiFrac Job Details

Well	True Depth of Horizontal (ft)	Delivery Method	No. of Fractures	Fracture Material	Sand/Acid Quantities	Completion Type	Relative Pressure (psi)
A	11,503 to 4,500	tubing	17	sand	10,000 lb	open	-400 to -1,200
B	3,821 to 1,600	tubing	8	acid	5,000 gal, 17%	open	small
C	8,800 to 1,000	tubing	1	sand	small	cased	small
D	1,700 to 1,300	tubing	3	sand	110,000 lb	slotted	small
E	10,860 to 4,600	coil	33	acid	300 gal, 28%	open	-100
F	10,850 to 1,000	coil	120	acid	250 gal, 15%	open	-2,000

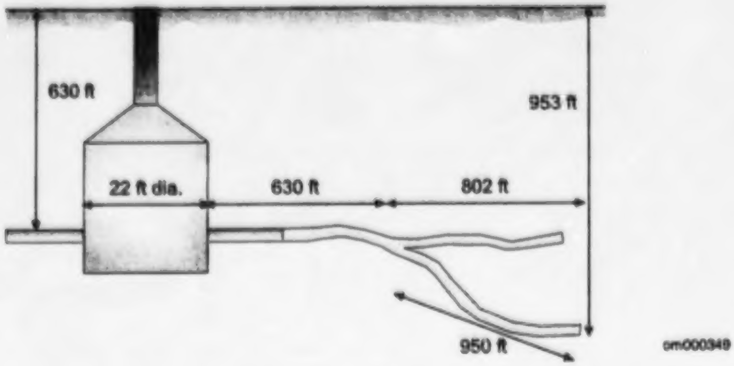

Fig. 1—First horizontal and multilateral well in First Cow Run Sand, Ohio.

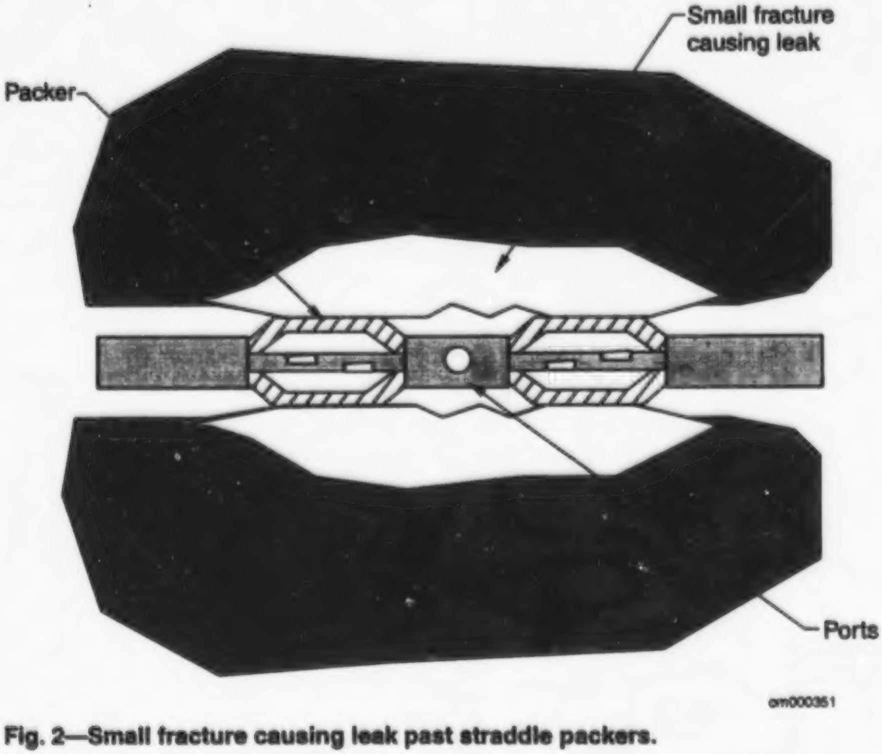

Fig. 2—Small fracture causing leak past straddle packers.

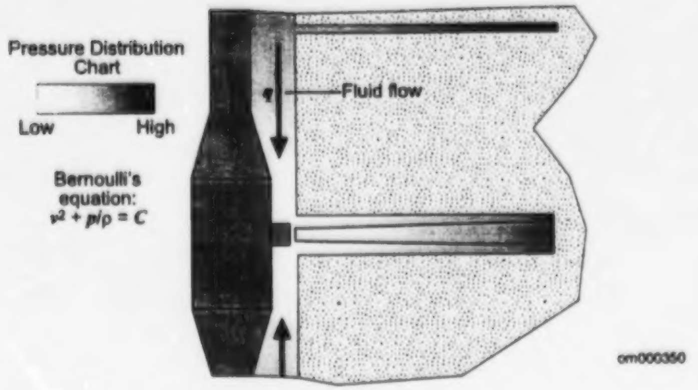

Fig. 3—The SurgiFrac process.

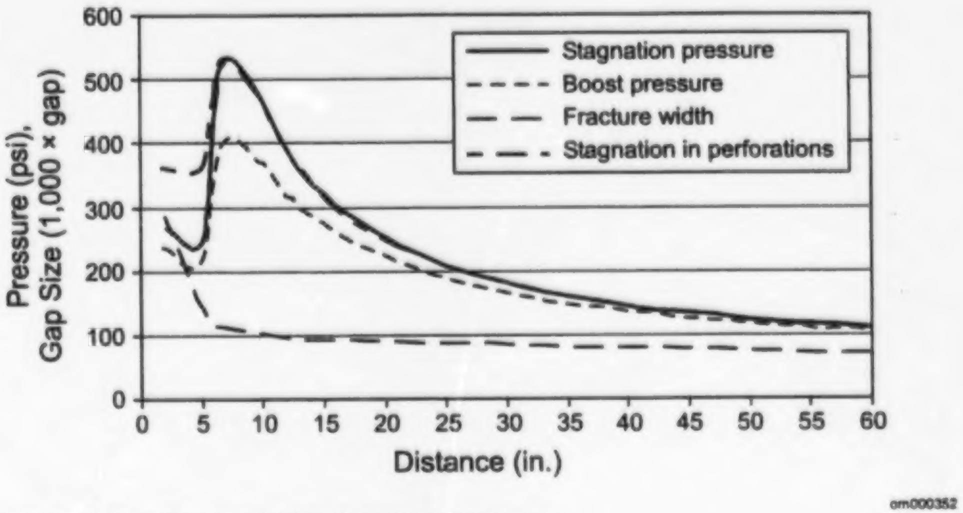

Fig. 4—Typical stagnation and boost pressures.

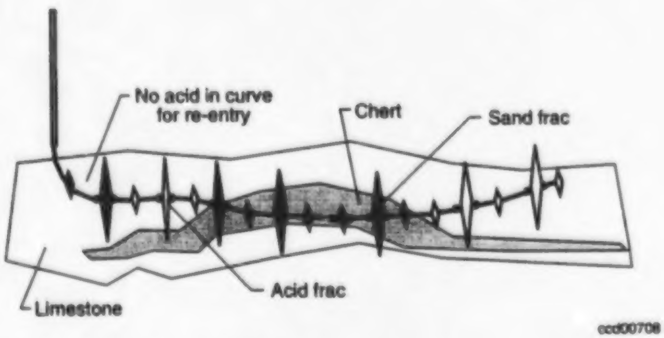

Fig. 5—Possible SurgiFrac completion.

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Fig. 6—SurgiFrac tool being inserted in Well B.

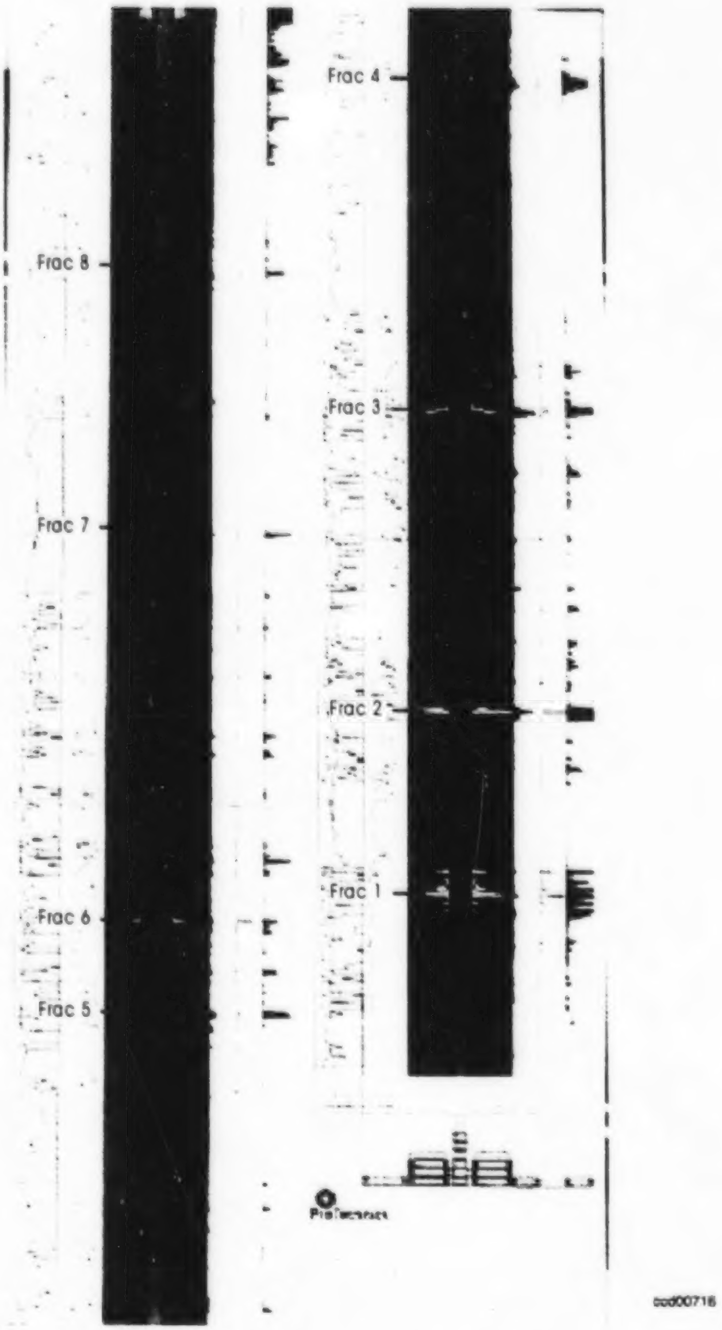


Fig. 7—Tracer log on Well B showing fractures at the planned location.

Downhole Oil-Water Separation
The "HYDROSEP"

International Williston Basin
Horizontal Well Workshop

April 27, 1999

Outline

- DOWNHOLE SEPARATION
  - What is it? Why do it? Economic justifications
- THE HYDROSEP
  - Vortoil Hydrocyclone, Separation Capacity, Limitations
- CANDIDATE WELL SELECTION
- FIELD INSTALLATION OPTIONS
- CASE HISTORIES
- CURRENT SITUATION/OPTIONS
- SUMMARY

What is Downhole Oil-Water Separation?

In-situ separation allows the well to produce a concentrated oil stream to the surface while simultaneously injecting clean produced water into the same wellbore.

Why Separation Downhole?

- Lower lifting costs
- Increase ultimate recovery
- Reduce capital expenditures
- Extend economic life of wells and fields
- Environmentally friendly
- Make marginal discoveries profitable

Economic Justifications

How does a downhole separator provide *incremental* oil and improved reserve recovery?

By reducing the associated water flowing along with the oil to the surface, some wells may be produced at a lower bottomhole pressure, thereby increasing the oil rate

Economic Justifications (cont.)

What makes a good candidate?

Look for a well with high pump intake pressure because production rate is limited by a "bottleneck"

- Tubing pressure drop constraints
- Flowline size
- Surface water-oil separator capacity
- Water storage / processing tank capacity
- Injection line size
- Injection well capacity
- Trucking / Fluid Treating costs

Environmental Justification

- Some oil fields have particular sensitivity to environmental issues
- AUEB requirements dictate that produced water brought to surface must be treated if the water is being re-injected into another zone

Downhole Oil-Water Separator

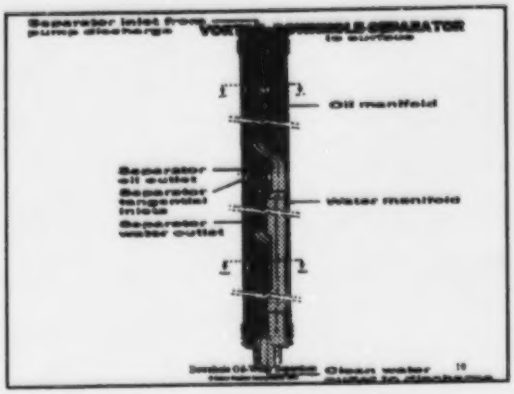
What is HydroSep?

- Baker Hughes **HydroSep** system is a downhole oil-water separator that combines **Baker Hughes Process Systems'** high performance **Vortoil** hydrocyclones with **Centrilift's** proven downhole pump systems and **Baker Oil Tools'** market-leading completion technologies

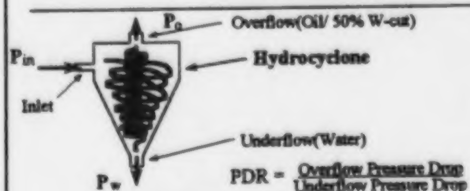
What is a VORTOIL Hydrocyclone?

A *STATIC* device that uses pressure energy to cause a rapid and efficient separation process

- Both Solid / Liquid and Liquid / Liquid hydrocyclones are available



HYDROCYCLONE OPERATION



$$PDR = \frac{\text{Overflow Pressure Drop}}{\text{Underflow Pressure Drop}}$$

$$PDR = (P_{in} - P_o) / (P_{in} - P_w)$$

Standard Target Value of PDR = 2.0

Acceptable Range : 1.7 < PDR < 4.0

VORTOIL Hydraulic Capacity

- The Hydrocyclone Tube chosen for Downhole Separation was chosen for high efficiency with maximum hydraulic capacity
- Single Tube Hydraulic capacity is 80 - 325 m^3/day (500 - 2,000 BFPD)
- Corresponding pressure drops are 350 - 1375 kPa (50 - 200 psi) inlet to water side

11

VORTOIL Hydraulic Capacity

- **140 mm (5-1/2") Cased Wells**
  114 mm (4-1/2") Separator Assembly holds up to 2 hydrocyclone tubes
  - **capacity 80 - 650 m^3/day (500 - 4,000 bpd)**
- **178 mm (7") Cased Wells**
  140 mm (5-1/2") Separator Assembly (has 152 mm (6.0" OD) collars) holds up to 5 tubes
  - **capacity 475 - 1600 m^3/day (3,000 - 10,000 bpd)**
- **245 mm (9-5/8") Cased Wells**
  194 mm (7-5/8") Separator Assembly holds up to 10 tubes
  - **capacity 1200 - 3200 m^3/day (7,500 - 20,000 bpd)**

VORTOIL Process Limitations

- Feed Emulsion Viscosity: Function of
  - Oil viscosity
  - Oil concentration
  - Temperature
- Limitation of 10 cP (maximum) for inlet fluid stream viscosity
- Oil / Water Density Difference
  - minimum difference is 2 °API

VORTOIL Process Limitations

•Free Gas

Free gas at the inlet to the separator may not exceed 10% v/v and must be designed for

Free gas is highly unlikely in the pump-thru' mode

•Solids

Solids do not affect separation in small quantities. They may, however, affect injectivity.

Candidate Well Selection

MANDATORY CHARACTERISTICS :

- **Injection Zone Available in Well**
- **High Water Cut Production (>70%)**
- **Casing size 140 mm (5 1/2") or bigger**

FAVOURABLE CHARACTERISTICS :

- High Water Lifting Costs
- High Water Handling / Disposal Costs
- High Pump Intake Pressure Due to Production "Bottleneck"

HYDROSEP SYSTEMS MONITORING OPTIONS

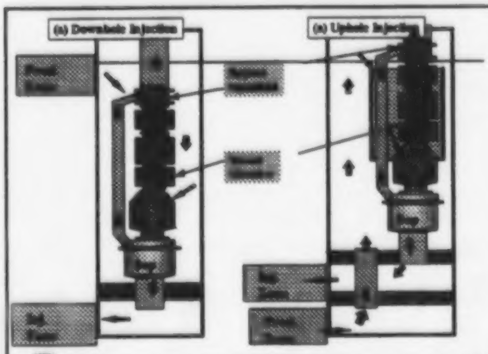
- **We recommend as a <u>minimum</u> that pump intake pressure and injection pressure be monitored.**
- **Real time injection flow rate is also recommended (An AUEB requirement if injecting into a different zone).**
- **Downhole pressure readings can be tied into our surface controller to vary the speed of the system to optimize production and separation efficiency should water cuts or injectivity change.**
- **A simple capillary line can be used to monitor injection water quality.**

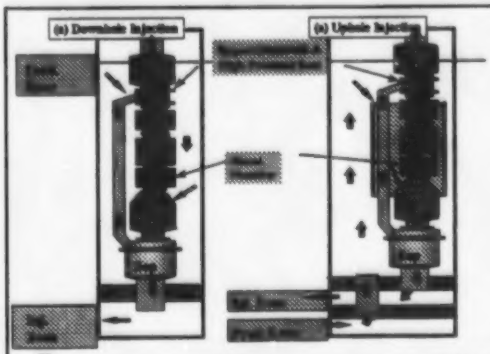
FUTURE INSTRUMENTATION NOTES

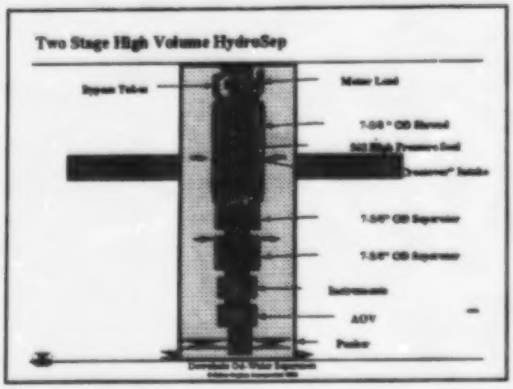
- **Future developments include surface-controlled AOV, fibre optic temperature and pressure profiling.**
- **Baker-Hughes is developing on enhanced version of our "Sentry" system capable of providing all real-time pressure measurements, flow rates and control required.**

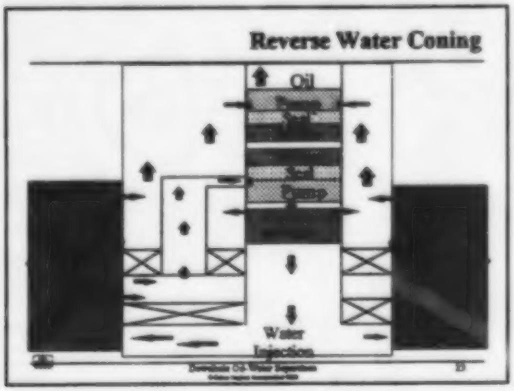
Field Installation Options

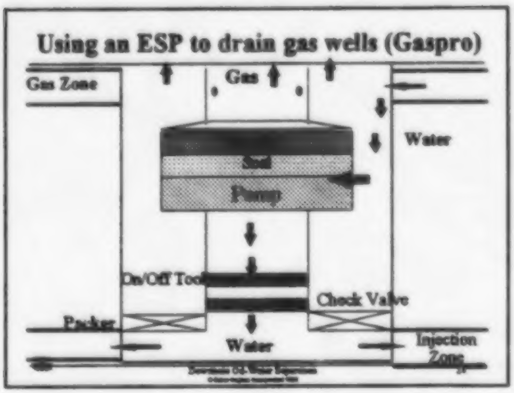
- Single or Dual Pumps
- Injection to Lower or Higher zones
- Single or Two Stage Hydrocyclone Geometry
- Reverse water coning
- Gas well dewatering (**Gaspro**)
- Cross-flooding



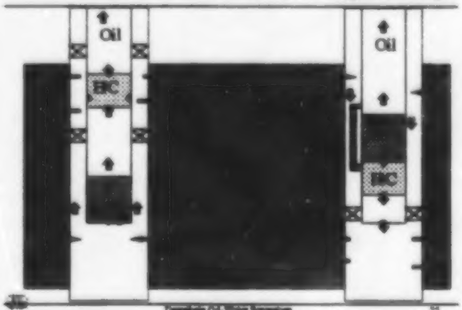



Two Stage High Volume HydroSep
Bypass Tubing
Motor Lead
AOV
Packer


Reverse Water Coning
Oil
Pump
Pump
Water
Injection
23


Using an ESP to drain gas wells (Gaspro)
Gas Zone
Gas
Water
Seal
Pump
On/Off Tool
Check Valve
Packer
Water
Injection
Zone

Cross Flooding - concept



CASE HISTORIES

- Byron / Garland, Wyoming
- Handsworth, Saskatchewan
- Bashaw, Alberta

BYRON/GARLAND, WYOMING

- Installed: July, 1997
- Geometry: Lower zone injection
- Injection Zone: Carbonate, 1325m; PZ=1204m
- Casing Size: 219.1mm (8 5/8")
- Production: Before - Oil: 11m3, Wtr: 628m3
  After - Oil: 12.4m3, Wtr: 53m3, Gas: 7mcf
  Disposal: 809m3 wtr.
- Status: Currently in service, additional units ordered

BYRON/GARLAND, WYOMING

ECONOMICS

- Water handling at surface was limited and costs to upgrade were prohibitive.
- After Hydrosep installation, water to surface was reduced 92% and incremental gas production was seen.
- After installation, offsetting well production was seen to increase due to pressure support from injection.
- Less injection wells needed as system acts as both a producer and an injector.

HANDSWORTH, SASKATCHEWAN

- Installed: June, 1997
- Geometry: Uphole zone injection (horizontal well)
- Injection Zone: Sand, 885m; PZ=1260m;
- Casing Size: 178mm (7")
- Production: Before - Oil: 14m3, Wtr: 288m3
  After - Oil: 21m3, Wtr: 62m3,
  Disposal: 388m3 wtr.
- Status: Pulled after 3 months; Injection zone sanded off.

HANDSWORTH, SASKATCHEWAN

ECONOMICS

- Water had to trucked; flowline tie-in costs were prohibitive
- After Hydrosep installation, power, trucking and treatment savings were $37K/mo.
- After installation, well was drawn down to gain incremental oil (@7m3/day @ $26K/mo.) and trucking costs were reduced to $3K/mo.
- System payout was calculated @ 3 months (i.e. $60K/mo. savings)

BASHAW, ALBERTA

- Installed: November, 1997
- Geometry: Lower zone injection
- Injection Zone: Carbonate, 1847m; PZ=1802m
- Casing Size: 139.7mm (5 1/2")
- Production: Before - Oil: 3m3, Wtr: 55m3
  After - Oil: 6m3, Wtr: 44m3, Disposal: 190m3 wtr.
- Well has approx 8% H_2S , 3% CO_2
- Status: Pulled after 9 month run; equip. scheduled to be rerun in another area.

BASHAW, ALBERTA

ECONOMICS

- Limited water handling capacity at surface
- After Hydrosep installation, maximum production is allowed to continue with less strain on surface facilities.
- System payout was calculated @ 12 months (based on incremental oil only)

CURRENT SITUATION/OPTIONS

- Worldwide install base totals @ approximately 20 systems.
- In Canada as many as 15 have been run.
- Other downhole separation systems exist based on other means of artificial lift.
- Surface hydrocyclone separation systems are also an option (eg. Peace River - Wellhead Separation in conjunction with downhole ESP unit).
- Surface skid mounted horizontal ESP pressure boost system coupled to a hydrocyclone available.

Downhole Separation: Summary

- Lowers lifting costs
- Increases ultimate recovery
- Reduces capital expenditures
- Extends economic life of wells and fields
- Environmentally friendly
- Makes marginal discoveries profitable

HydroSep Downhole Oil-water Separator:

- Baker Hughes **HydroSep** system combines **Baker Hughes Process Systems'** high performance **Vortoil** hydrocyclones with **Centrilift's** proven downhole pump systems and **Baker Oil Tools'** market leading completion technologies

Additional Information can be downloaded from http://www.bakerhughes.com/centrilift/

THE IMPACT OF FORMATION DAMAGE IN A HORIZONTAL WELLBORE: EXPERIMENTAL AND NUMERICAL STUDIES

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Abstract

Formation damage can often render an otherwise productive well into a non-productive well. Before a comprehensive design can be performed, one should have a better understanding of the physics of formation damage, as applied in a horizontal wellbore. A series of experiments using Berea sandstone cores was conducted in a controlled laboratory environment in order to assess the extent of fines migration in a horizontal wellbore. The effect of the fines migration in the vicinity of the wellbore was determined. Also observed is the effect of flow rate, fines content and others. It was observed that the conventional wisdom regarding more plugging near the heel of the wellbore is not accurate. Experimental results of fines deposit in the wellbore was measured using a computerized permeameter (PDPK-200). This was followed by mathematical modeling of fines migration. A recently developed theory was extended in order to assess damage in the wellbore as a function of flow rate, fines content, and permeability. Excellent agreement between experimental and numerical results was observed. Finally, the numerical model was extended to field application in order to describe performance in the field scale. This simulator can become an effective tool for assessing wellbore plugging due to fines migration and can be extended to modeling formation damage in unconsolidated sand as well.

*Currently with Intevep, Venezuela

NEW SCREENING CRITERIA FOR SELECTION OF ACID-FOAM SURFACTANTS

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ABSTRACT

A new method is proposed for screening surfactants suitable for foam diversion purposes. Surfactant screening is an important task in the processes that involve the use of foam. Several screening methods have been developed, including static tests and porous media tests. However, they are neither dependable nor standard. Six different surfactants are tested in this study. These surfactants were selected among a foray of 'best-performing' surfactants supplied by six service- and chemical companies.

The new technique requires an inexpensive setup, a simple experimental procedure, and simple calculations. A new surfactant screening technique was developed in which optimum values of parameters such as ultimate liquid recovery, recovery at breakthrough, cumulative liquid produced to cumulative air produced (L/A) ratio, maximum blocking pressure, liquid mobility ratio (P2/P1) and breakthrough time during the porous media tests, were used to select the surfactants that are most likely to help diversion.

A series of coreflood tests, both in a single core and a dual-core, was conducted in order to compare the ranking that was obtained following the high-permeability porous media tests. The results are in excellent agreement. Also, bottle tests were conducted and it was demonstrated that the bottle test results do not match the results of high-pressure core flood tests. Some porous media tests were conducted in the presence of residual oil in the system. Results indicate that for screening of surfactants, it is not necessary to have oil in the system. This observation was supported by dual-core diversion tests conducted in the presence of oil. Similarly, there is no need to use acid during the screening process.

The proposed screening method can be applied in both foam acidization as well as enhanced oil recovery processes. The method uses porous media and standardizes the surfactant screening procedure.

Preliminary Announcement

for the

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